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# ADVANCED RESERVOIR CHARACTERIZATION IN THE ANTELOPE SHALE TO ESTABLISH THE VIABILITY OF $CO_2$ ENHANCED OIL RECOVERY IN CALIFORNIA'S MONTEREY FORMATION SILICEOUS SHALES

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By
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Chevron USA Production Company
Bakersfield, California

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# Advanced Reservoir Characterization in the Antelope Shale to Establish the Viability of $CO_2$ Enhanced Oil Recovery in California's Monterey Formation Siliceous Shales

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# ABSTRACT

This report describes the evaluation, design, and implementation of a DOE funded $CO_2$ pilot project in the Lost Hills Field, Kern County, California.

The pilot consists of four inverted (injector-centered) 5-spot patterns covering approximately 10 acres, and is located in a portion of the field, which has been under waterflood since early 1992. The target reservoir for the $CO_2$ pilot is the Belridge Diatomite. The pilot location was selected based on geology, reservoir quality and reservoir performance during the waterflood. A $CO_2$ pilot was chosen, rather than full-field implementation, to investigate uncertainties associated with $CO_2$ utilization rate and premature $CO_2$ breakthrough, and overall uncertainty in the unproven $CO_2$ flood process in the San Joaquin Valley.

This report summarizes the methodology used in the project evaluation and design including construction of the geologic model, reservoir simulation and $CO_2$ flood predictions, facilities design, and well design and completion considerations. An actual $CO_2$ injectivity test was conducted in March 1999. The results of the injectivity test, which helped in the design of the pilot, are presented.

The reservoir management plan and future field potential are also discussed. $CO_2$ injection in the pilot is planned to commence in June of 2000. The methodology and technical analysis used to evaluate and design the Lost Hills $CO_2$ pilot are applicable to other potential San Joaquin Valley $CO_2$ floods.

# EXECUTIVE SUMMARY

**Introduction:**
The primary objective of our project was to conduct advanced reservoir characterization and modeling studies in the Antelope Shale of the Buena Vista Hills Field. Work was subdivided into two phases or budget periods. The first phase of the project would focus on a variety of advanced reservoir characterization techniques to determine the production characteristics of the Antelope Shale reservoir. Reservoir models based on the results of the characterization work would then be used to evaluate how the reservoir would respond to enhanced oil recovery (EOR) processes such as of $CO_2$ flooding. The second phase of the project would be to implement and evaluate a $CO_2$ in the Buena Vista Hills Field. A successful project would demonstrate the economic viability and widespread applicability of $CO_2$ flooding in siliceous shale reservoirs of the San Joaquin Valley.

However, it was decided not to proceed with a Phase II field trial in Buena Vista Hills because of its very low oil saturation, lithologic heterogeneity and relatively few natural fractures in the siliceous shale reservoirs. Although Buena Vista Hills turned out to be a poor $CO_2$ EOR candidate, our reservoir characterization has demonstrated that under the right conditions, $CO_2$ is a viable enhanced recovery process for other siliceous shales. Therefore, the Phase II $CO_2$ pilot was moved to Lost Hills Field, about 30 miles north of Buena Vista Hills with the DOE's concurrence.

**Lost Hills Field:**
The target reservoir at Lost Hills is the Belridge Diatomite of the Monterey Formation. The Belridge Diatomite is a diatomaceous mudstone and is not present at Buena Vista Hills. The diatomite has high oil saturation (50%) and high porosity (45 - 70%), but its low permeability (<1 millidarcy) has led to low primary oil recovery (3 - 4% of OOIP). Due to the low primary recovery and large amount of remaining oil in place, Lost Hills presents an attractive target for EOR. In addition to the large resource base, there is technical and economic justification for $CO_2$ flooding that was developed through our reservoir characterization and simulation efforts. The oil response for four different recovery processes at Lost Hills at three different well spacings (2-1/2, 1-1/4, 5/8 acres) were evaluated:

- Primary (Hydraulically Fractured Wells)
- Waterflood
- Steamflood
- $CO_2$ Flood

Forecasts were then generated using Chevron proprietary reservoir simulation software. The results of this simulation are shown in Figure ES-1. One process, in particular, really does stand out. $CO_2$ flooding shows tremendous oil response relative to the other three processes, mainly due to improved injectivity. $CO_2$ injectivity is at least two to three times greater than that of water or steam at 2-1/2 acre spacing. The injection of $CO_2$ will also reduce reservoir oil viscosity and increase fluid expansion.

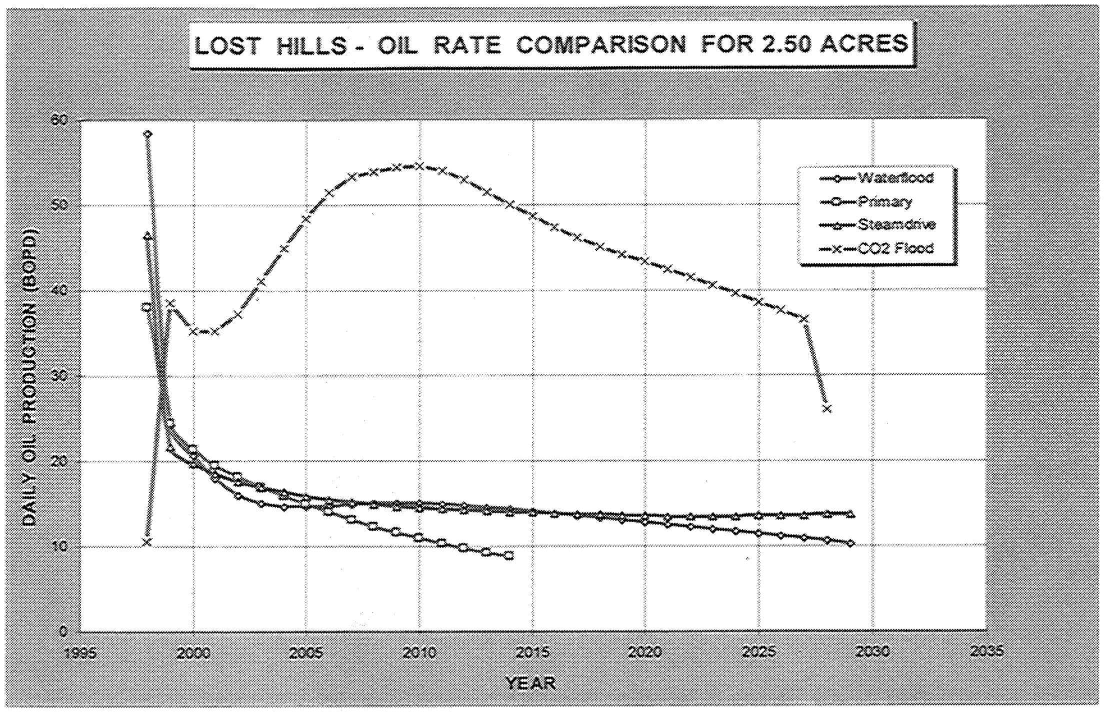


**Figure ES-1. Comparison of various IOR processes at Lost Hills.**

Preliminary economics for full-scale implementation of a $CO_2$ Flood in Lost Hills has identified several key uncertainties which will be evaluated as part of the pilot planning. The main economic uncertainties that can only be further evaluated by the pilot are oil response, and the corresponding $CO_2$ utilization required for such a response. The pilot has been designed and planned to significantly reduce the range of uncertainty for these two key items. Funding is also included in this project to further evaluate the feasibility and cost of local long-term $CO_2$ supplies. Since it is very unlikely that a $CO_2$ pipeline to California will be built anytime soon, success of a full-scale $CO_2$ flood will depend on utilization of $CO_2$ entrained in local produced gas and flue gas. Global warming and future world emission trading of $CO_2$ credits may drastically increase the availability and lower the cost of $CO_2$ in California. As part of project scoping the $CO_2$ Team will continue to track developments for global warming.

**Background & Present Situation:**

The Lost Hills Field, located 45 miles northwest of Bakersfield, California, was discovered in 1910. Reserves in the shallow sands, diatomite, and chert pools were developed using slotted liner completion techniques until the late 1970's. From the late 1970's to 1987, small volume hydrofracture completions were performed covering the entire Belridge Diatomite.

Advances in hydraulic fracturing technology in the late 1980's resulted in increased oil recovery that led to a more aggressive development program by Chevron. From 1987 to the present, high volume hydrofracture completions have been performed across the entire Belridge Diatomite and the Upper Brown Shale resulting in significant production increases. The Lost Hills Field is developed on a 5 acre (siliceous shale) to 1.25 acre (diatomite) well spacing. There are over 2.2 billion barrels of oil in place in the Belridge Diatomite in Lost

Hills. To date only 112 million barrels have been produced, or approximately 5% of the original oil in place (OOIP).

Chevron initiated a pilot diatomite waterflood project in December 1990 and began full-project development in April 1992. Since 1992, two hundred and eight 2-1/2 acre patterns have been put on water injection spanning parts of four sections (Sections 4, 5, 32 Fee, and 33). Since the initiation of first project water injection in April 1992, production has increased approximately 4,000 BOPD from 6,400 BOPD to the current rate of 10,400 BOPD.

**Proposal:**
Install a four-pattern, 2.5 acre pilot on Section 32 Fee to evaluate $CO_2$ flooding of the Lost Hills Diatomite. The scope of the pilot includes: remedial work to evaluate and upgrade the tubing and packers in the injectors, possible drilling of up to 4 replacement injectors, 3 observation wells, liquid $CO_2$ injection facilities, injection lines, dedicated gauging facilities, and extensive monitoring. It is anticipated that $CO_2$ injection could commence as early as June, 2000. The pilot will be evaluated for a period of 6 months to 2 years. Reservoir simulation predicts that oil response would not occur for several years. However, based on the results of the injectivity test, a quicker response time is now expected.

**Objectives:**
A $CO_2$ a pilot will be installed in Section 32 Fee of the Lost Hills field to test the technical and economic viability of $CO_2$ flooding the low permeability diatomite resource. A full-scale $CO_2$ project is economically justified by an incremental analysis and comparison to the current base case waterflood. Incremental tertiary reserves are estimated to be 80 MMBOEG and are technically supported by reservoir simulation. However, the project is only marginally economic and considerable uncertainty exists in the magnitude of predicted $CO_2$ recoveries. Installing a pilot will provide us with an opportunity to gather and analyze the pertinent geologic, reservoir, and production data and gather facilities design information necessary to commit to a full-field project. In addition, the pilot capital and operating costs will take advantage of available DOE funding of nearly 2.7 million dollars.

**Additional Objectives:**
There following are additional objectives of the proposed $CO_2$ pilot:

- Gain information that could benefit other drive mechanisms in Diatomite such as:
    - Learn how injecting a gas (very low viscosity fluid) differs from injecting water into the diatomite in terms of fracture azimuth, injectivity, and areal and vertical sweep.
    - Mitigation measures for $CO_2$ breakthrough problems can be applied to other IOR operations.
    - Learn how much of the diatomite pay zone can effectively be processed. This knowledge can be applied to other IOR process designs.
    - Learn how to mitigate and/or control hydrofracture growth (vertically and areally).

- Potential Federal Regulations may make $CO_2$ a "free" commodity 5 to 10 years down the road. Injecting $CO_2$ may be used to offset emissions from other nearby Chevron facilities.

**Risks:**
The pilot has been design and planned to both minimize risk for the pilot and to better assess risk for the full-scale project. Some of the significant risks for the pilot and project are:

- Premature breakthrough of $CO_2$
- Oil response is not measured well
- Temporary loss of liquid $CO_2$ supply
- Excessive corrosion from gas high in $CO_2$ concentration

**Facility Alternatives:**
Since $CO_2$ equipment and purchases constitute the bulk of the expenditures for the pilot, several alternatives were considered. The primary strategies ended up being "Liquid $CO_2$" versus "Amine $CO_2$". Liquid $CO_2$ is supplied from California refineries via truck while the "Amine $CO_2$" would involve the installation of an amine process $CO_2$ removal plant in Lost Hills (to remove $CO_2$ from produced gas that is 15% $CO_2$ by volume). Decision Analysis was used to determine the NPV for each alternative and the factors that could influence the final value. The analysis showed that liquid $CO_2$ is more economical for a pilot lasting less then 2 or 3 years.

# ACKNOWLEDGMENTS

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SECTION 1.

# PRESENT SITUATION

# 1.1 GEOLOGY

## Overview of Lost Hills Geology

Lost Hills Field was discovered in 1910 and is located 40 miles northwest of Bakersfield, CA (Figure 1.1-1). Productive intervals include Middle to Upper Miocene diatomite, chert, porcelanite, and siliceous shale, and Plio-Pleistocene sands. The field is situated along a northwest-southeast trending series of structural highs that begins with the Coalinga Anticline to the northwest and culminates with the Lost Hills Anticline to the southeast. This series of highs roughly parallels folds of similar age on the westside of the San Joaquin Valley. These folds are oriented nearly parallel to the trend of the San Andreas Fault to the west and approximately perpendicular to the direction of regional compression.

Lost Hills oil is trapped at the crest and along the southeast plunge of the anticline (Figures 1.1-2 - 4). In this portion of the field where the pilot will be located, the structural plunge varies from 2 to 6 degrees toward the southeast. Dips along the northeast flank average around 30 degrees while those on the southwest flank average around 15 to 20 degrees. This asymmetry in dips in the NE-SW direction is consistent with a fault-bend fold model. This model predicts that structural growth of the Lost Hills Anticline was initiated during latest Miocene time and that the resulting anticline is perched above a ramp thrust that is located around 13,000 feet below the surface. Numerous northeast-southwest trending normal faults with throws rarely exceeding 40 feet cut the Lost Hills structure. These faults do not appear to effect production.

The stratigraphy at Lost Hills is shown in Figures 1.1-3 and 1.1-5. The Monterey Formation is comprised of the Devilwater Shale, McLure Shale and Reef Ridge members. The Devilwater consists of shales and siliceous shales. It is slightly phosphatic. The McLure is subdivided into the McDonald Shale and the Antelope Shale. The McDonald consists of interbedded porcelanites and siliceous shales. It is also slightly phosphatic. The Antelope is comprised of finely laminated cherts and porcelanites. The uppermost member of the Monterey Formation is the Reef Ridge and it is subdivided into the Brown Shale and Belridge Diatomite. The Brown Shale is made up of interbedded siliceous shale, shale, and silt. The Belridge Diatomite consists of interbedded diatomaceous mudstone, fine-grained, argillaceous sands/silts, and porcelanite.

Based on regional studies of late Miocene paleogeography and paleobathymetry, the rocks of the Monterey Formation were deposited in a deep marine environment. In the San Joaquin Basin, the late Miocene environment was such that: water depths were bathyal (between 600 and 3,000 feet), cool water temperatures and upwelling in the upper 200 feet supported large diatom populations, and the deeper basin waters were oxygen poor. Two primary sedimentation processes were active in the basin at that time. First, hemipelagic sedimentation: the settling of diatom frustules and clay-sized particles onto the basin floor from the overlying water column. And second, turbidite sedimentation: the deposition of sand, silt, and clay-sized particles carried into the basin by density currents (usually originating along the basin margins).

This combination of environmental conditions and sedimentation processes led to the accumulation of thick deposits of organic-rich, laminated, diatomaceous sediments which occasionally are interrupted by thin-bedded, clastic-rich turbidite deposits. However, compared to the southwestern San Joaquin Basin, sandy turbidites at Lost Hills are not common. The Monterey Formation in the San Joaquin Basin differs from the coastal and offshore Monterey in that it is much more clastic rich.

The composition of the Monterey can be described in terms of three primary components: biogenic silica, clay, and silt/sand. As shown in Table 1.1-1, there is a fair amount of vertical compositional variation within the stratigraphic column at Lost Hills. The Devilwater contains 27% biogenic silica, 50% clay, and 23% silt/sand. The McDonald is slightly richer in biogenic silica, roughly comparable in clay, and slightly lower in silt/sand. The Antelope is very rich in biogenic silica, poor in clay, and poor in silt/sand. The Brown Shale is clay rich. The Belridge Diatomite has roughly equal amounts of biogenic silica, clay and silt/sand. The overlying Etchegoin Formation is rich in silt/sand and clay, and almost totally lacking in biogenic silica.

**Table 1.1-1. Average rock compositions from Well 166, Section 32, T26S/R21E.**

| Rock Unit | Average. % Biogenic Silica | Average % Clay | Average % Silt/Sand | Number of Samples |
|---|---|---|---|---|
| Etchegoin | 4 | 38 | 58 | 8 |
| Belridge Diatomite | 33 | 36 | 31 | 19 |
| Brown Shale | 26 | 47 | 27 | 28 |
| Antelope Shale | 61 | 18 | 21 | 14 |
| McDonald Shale | 34 | 47 | 19 | 24 |
| Devilwater Shale | 27 | 50 | 23 | 8 |

As hemipelagic and occasional turbidite deposits in the Lost Hills area were buried by the overlying Etchegoin and Tulare sediments, the diatomaceous sediments of the Monterey Formation gradually lithified into the highly porous (50-60% or more) but impermeable (0.1-10.0 millidarcy) rock termed diatomite. As discussed above, anywhere from 26% to 61% of this diatomite was composed of diatom frustules. Diatom frustules consist of a form of silica called opal-A, which is an unstructured mineral (essentially a solidified gel) usually containing 3-10% water. As this diatomite is buried deeper and reaches greater temperatures (40-50 degrees C), the opal-A material in the diatom frustule becomes unstable and undergoes a phase transition to opal-CT (Figures 1.1-6 - 7). This form of silica is more structured than opal-A and has released much of its water. Porosity is reduced to ~40%. At still greater depths and higher temperatures (80-90 degrees C), the opal-CT undergoes a final phase transition to a form of quartz with only a trace of water left. The Monterey Formation at Lost Hills is presently comprised of opal-A rocks at shallow depths (± 2,300 feet or shallower), opal-CT rocks at intermediate depths (±2,300 to ± 4,300 feet), and quartz phase rocks below ± 4300 feet.

The exact temperatures at which the opal-A to opal-CT and opal-CT to quartz phase changes occur is governed by the amount of biogenic silica (diatoms) in the rock. Opal-A rocks rich in biogenic silica convert to opal-CT at lower temperatures (and therefore shallower depths) than those poor in biogenic silica. Conversely, opal-CT rocks rich in biogenic silica convert to quartz phase at higher temperatures (and greater depths) than those poor in biogenic silica. For this reason, an interval of rocks whose laminations vary in their biogenic silica content create a transition zone of laminated phases near the phase transition temperature. The laminated phases in these transition zones (particularly where the laminae are thin) may be especially susceptible to natural fracturing, thereby enhancing system permeability. Volume reduction and water expulsion associated with the phase changes probably adds to the fracturing in these zones. In general, hydrocarbons are found in all three (opal-A, opal-CT, and quartz) phases. Also production is enhanced in the opal-A to opal-CT and, in particular, the opal-CT to quartz phase transition zones.

Geochemical analyses have demonstrated that Monterey Formation rocks in Lost Hills are typically composed of 1% to 6% total organics, making them fair to good hydrocarbon source rocks. Studies of kerogen maturation have shown that the Monterey rocks are immature (i.e., they have not been buried deep enough to generate oil) within the confines of the Lost Hills Field. However, studies of samples taken from down-flank wells indicate that these rocks are mostly mature in the syncline to the east of Lost Hills and possibly below the ramp thrust immediately beneath the Lost Hills Anticline. Because the Monterey Formation kerogens and the produced oils at Lost Hills have similar isotopic compositions, and because they contain similar concentrations of sulfur, it is believed that Lost Hills oil was sourced from the Monterey Formation itself.

Hydrocarbons migrated into the low permeability Monterey rocks at Lost Hills by way of faults, fractures and thin sands. Also the opal-A to opal-CT and opal-CT to quartz phase transition zones with their higher fracture density probably served as pathways for hydrocarbons to migrate from source beds down-structure to their ultimate resting place in the crest of the anticline.

In the McDonald Shale and Lower Brown Shale/Antelope Shale pools, hydrocarbons are confined fairly well within or immediately below the fractured opal-CT to quartz phase transition rocks. In the Upper Brown Shale, fracturing also helps to make it productive. Because the McDonald, Antelope, and Brown shales have such low matrix permeability, most of the oil produced from these rocks comes out of the fractures. In the Belridge Diatomite with its relatively higher matrix permeability, hydrocarbons have saturated the uppermost opal-CT, the opal-A to opal-CT transition, and most of the opal-A rocks. Most of the oil produced from the diatomite comes from the matrix. Lastly, some oil has even migrated into the overlying Etchegoin and Tulare Formations.

Pilot Location and Belridge Diatomite

The target reservoir for the $CO_2$ pilot in Lost Hills is the FF – L interval of the Belridge Diatomite (Figures 1.1-8 - 13). In the pilot area, the diatomite is in opal-A phase. The lower half of the Belridge Diatomite is comprised of approximately equal parts of biogenic silica (diatoms), silt/sand, and clay while the upper half is comprised mainly of silt/sand, clay, and minor biogenic silica. The diatomite is finely laminated. In general these laminations alternate between a more detritus rich lamina and a more diatomaceous rich lamina. The laminations reflect cyclic variations in yearly runoff (detritus rich) and upwelling (diatomaceous rich).

Superimposed on this depositional cycling are the changes in relative sea level that occurred in the Upper Miocene. As sea level rose, diatomaceous rich deposits were deposited further up on the slope. As sea level fell, sandy diatomite deposits prograded down the slope. These fluctuations in sea level caused the larger scale deposition of sedimentary units of "clean" diatomite, "clayey" diatomite, and "sandy" diatomite. The diatomites were deposited under oxygen poor to anoxic conditions that could sustain only a limited sediment-dwelling fauna. Thus laminations are preserved in the diatomites. Meanwhile sandy diatomites were deposited under oxygen poor to oxygenated conditions. Sandy diatomites were originally deposited as interlaminated sands and clays but shortly after deposition were heavily bioturbated. Lastly, superimposed on the sea level changes was the overall progradation of the shelf, which resulted in the coarsening upward of the Belridge Diatomite, and the eventual filling in of the basin in the Pliocene.

As described above, the Belridge Diatomite is comprised of varying amounts of diatomaceous material, clay, and silt/sand. In Lost Hills, the Belridge Diatomite ranges in depth from 800 to 3,000 feet. Oil gravity ranges from 28 to 18 degrees API. Although porosity is very high (40 - 65%), permeability is very low (<1 – 10 millidarcies). Oil saturation ranges from 40% to 65% in opal-A and from 10% to 30% in opal-CT (Table 1.1-2).

**Table 1.1-2. Comparison of rock types at the newly proposed pilot location (Lost Hills) and the original location (Buena Vista Hills).**

| Parameter | Lost Hills Pilot | Buena Vista Hills Pilot |
|---|---|---|
| Rock Unit | Belridge Diatomite | Upper Antelope Shale |
| Age | Uppermost Miocene | Upper Miocene |
| Depositional Environment | Hemipelagic; Progradational Slope | Hemipelagic-Turbidite; Basin |
| Rock Type | Diatomaceous Mudstone | Siliceous Shale |
| Silica Phase | Opal-A | Opal-CT |
| Percent Sand Beds | 30% | 5% |
| Sand Description | 5-60 feet thick, fine-grained, argillaceous, bioturbated | <1 inch thick, fine-grained, non-bioturbated |
| Depth to Top of Unit | 1,400 feet | 4,200 feet |
| Thickness | 700 feet | 600 feet |
| Porosity | 50% | 29% |
| Permeability | 0.1 – 10.0 millidarcies | <0.1 millidarcies |
| Oil Saturation | 50% | 14% |

Development of the Lost Hills Field has evolved over the years. From 1910 to the late 1970's, slotted liner completions were used in the upper Belridge Diatomite. From the late 1970's to 1987, small volume hydrofrac completions were performed covering the entire Belridge Diatomite. From 1987 to the present, high volume hydrofrac completions have been performed across the entire Belridge Diatomite and the Upper Brown Shale. Since

1992 a portion of the diatomite has been under waterflood, and in 1998 a pilot steam-drive was started. The Lost Hills Field is developed on a 5 acre (siliceous shale) to 1.25 acre (diatomite) well spacing. Evaluations on closer well spacings are also in progress. There are over 2 billion barrels of oil in place in the Belridge Diatomite in Lost Hills. Due to the reservoir's low permeability less than 6% of this oil has been produced.

**Natural Fractures and Thief Zones:**
In general, all wells are hydraulically propped fractured in Lost Hills. Occasionally these hydraulic fractures intersect other existing producing wells causing them to sand-up, or increase water production if an injection well communicates with it. These are induced fractures. Hydraulic fractures intersecting existing wells can be the result of many factors. These include: 1) wells being in fracture alignment; 2) existing faults/fractures; and 3) localized areas of depletion due to production, or localized areas of re-pressurization from injection that cause the hydraulic fracture to propagate at an azimuth that is not in aligned with the natural stress field. In the case of the communication between the 12-8D and 11-8D during the $CO_2$ injectivity test, this most probably was the result of these two wells being in hydraulic fracture alignment.

Recent fracture analysis by D. Julander using Electrical Micro Imaging (EMI) logs, and log data from the OB-7 and 12-8D wells allows for observations to be made regarding the abundance of natural fractures and thief zones (Figures 1.1-14 - 15). The EMI from the $CO_2$ injectivity test well 12-8D is fairly representative of this part of the Lost Hills Field. It shows a fracture frequency between 1 and 3 fractures per 10 feet of vertical interval. This fracture frequency includes all observable fractures: open, closed (clay-filled), and fractures of undeterminable type (due to being poorly imaged).

With regards to thief zones, i.e., high permeability sands interbedded within the diatomite, there does not appear to be a large body of evidence to support this idea. Recent data from the nearby OB-7 well (1,160 feet SW of 12-8D) clearly exemplifies this. OB-7 was drilled and cored only 20 feet (perpendicular to fracture azimuth) from a water injection well (10-9W) that was drilled in 1994. Core PKS data clearly shows that the sandy diatomites from OB-7 do not have highly reduced oil saturations compared to the original injector. As stated above and illustrated in Figures 2.1-12 and 13, the sandy diatomites are clay rich and bioturbated. These features make it very difficult to behave as a thief zone. Also, the $CO_2$ injection profiles from 12-8D and 12-7W (Figure 1.1-16) also indicate that that $CO_2$ did not have a preference for the sandy diatomites.

In summary, while there are fractures and faults present in the diatomite, the reservoir should not be considered a highly fractured reservoir. However it should also be said that based on tiltmeter analysis of $CO_2$, water, and steam injectivity tests in Lost Hills, it appears that fractures and faults do play a role in the unpredictable distribution of low viscosity fluids at low injection rates. This is another reason why a pilot is necessary.

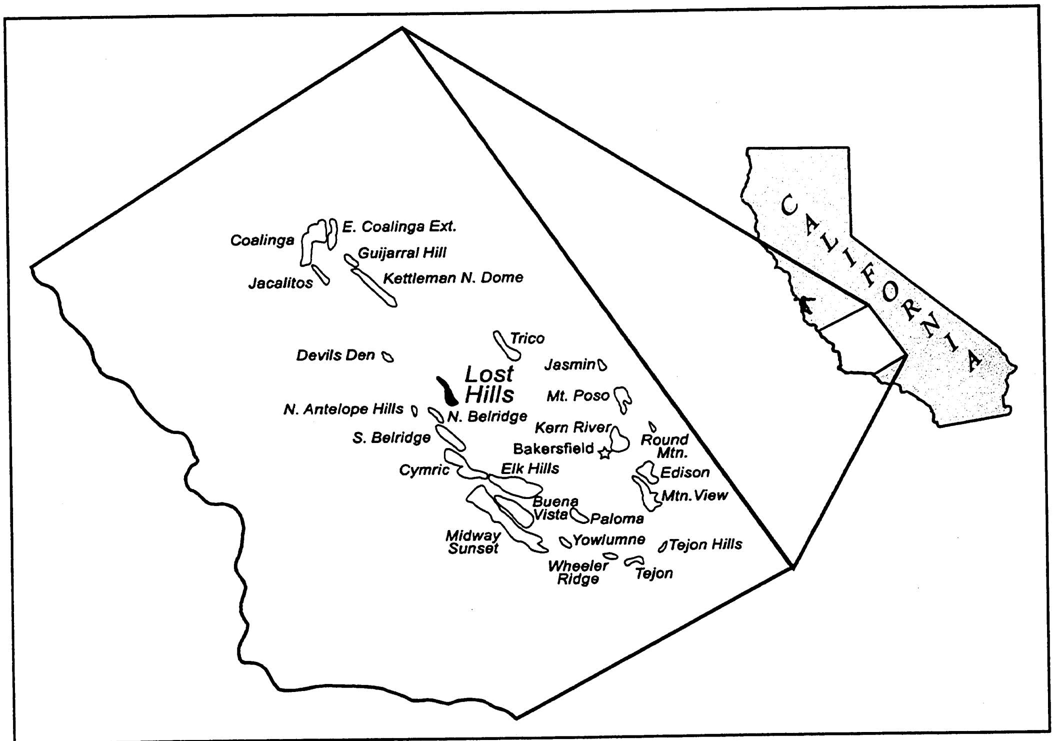



**Figure 1.1-1. Location map of major oil fields in the southern San Joaquin Valley. Lost Hills Field is highlighted.**

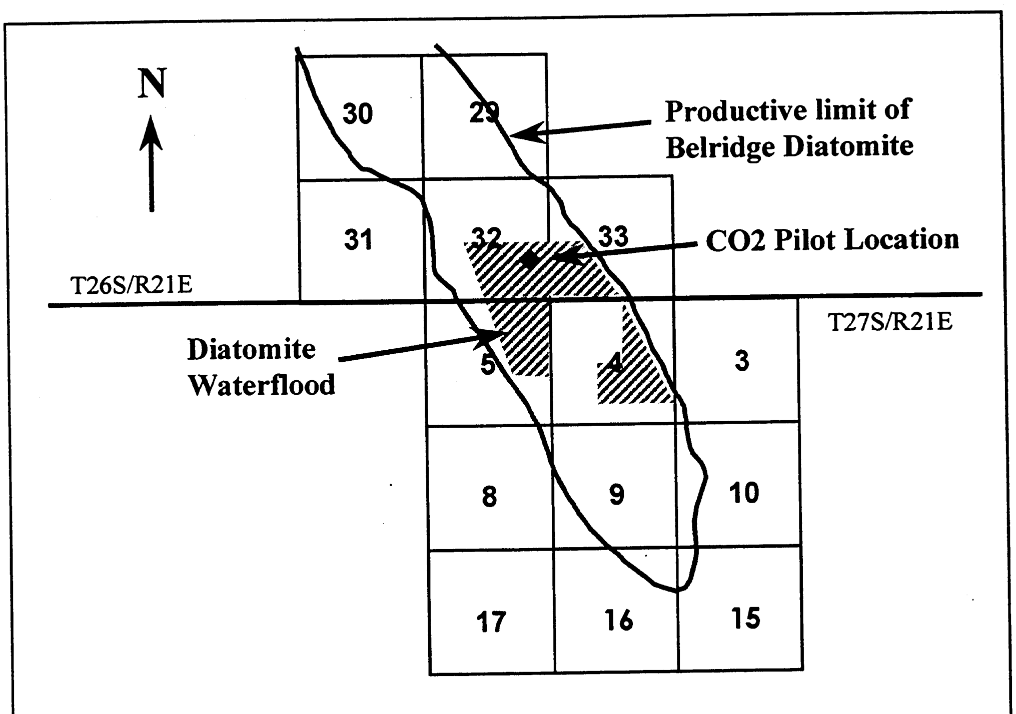



**Figure 1.1-2. Productive limits of Belridge Diatomite follows trend of southeast plunge of the Lost Hills Anticline.**

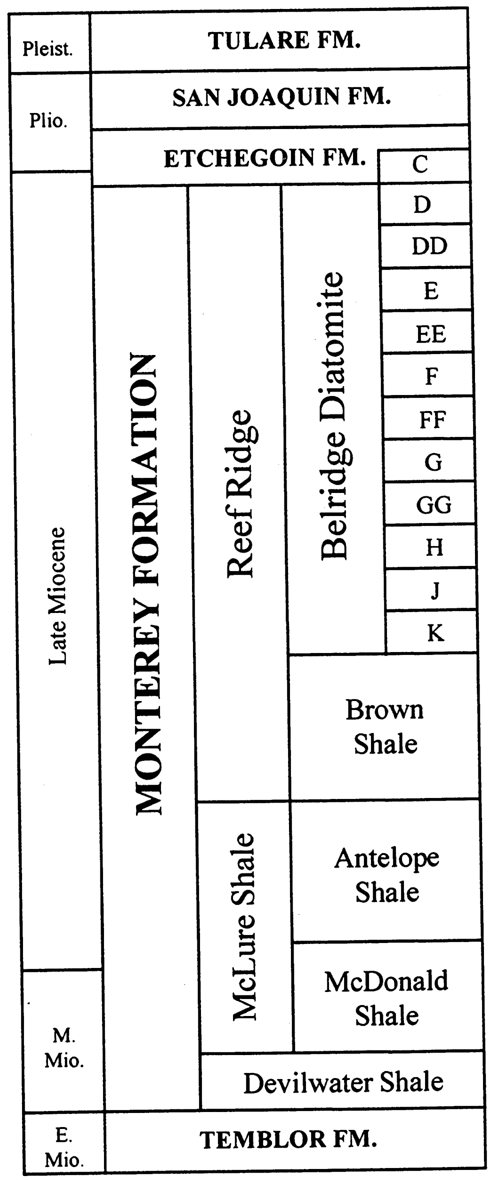



**Figure 1.1-3. Lost Hills stratigraphic column.**

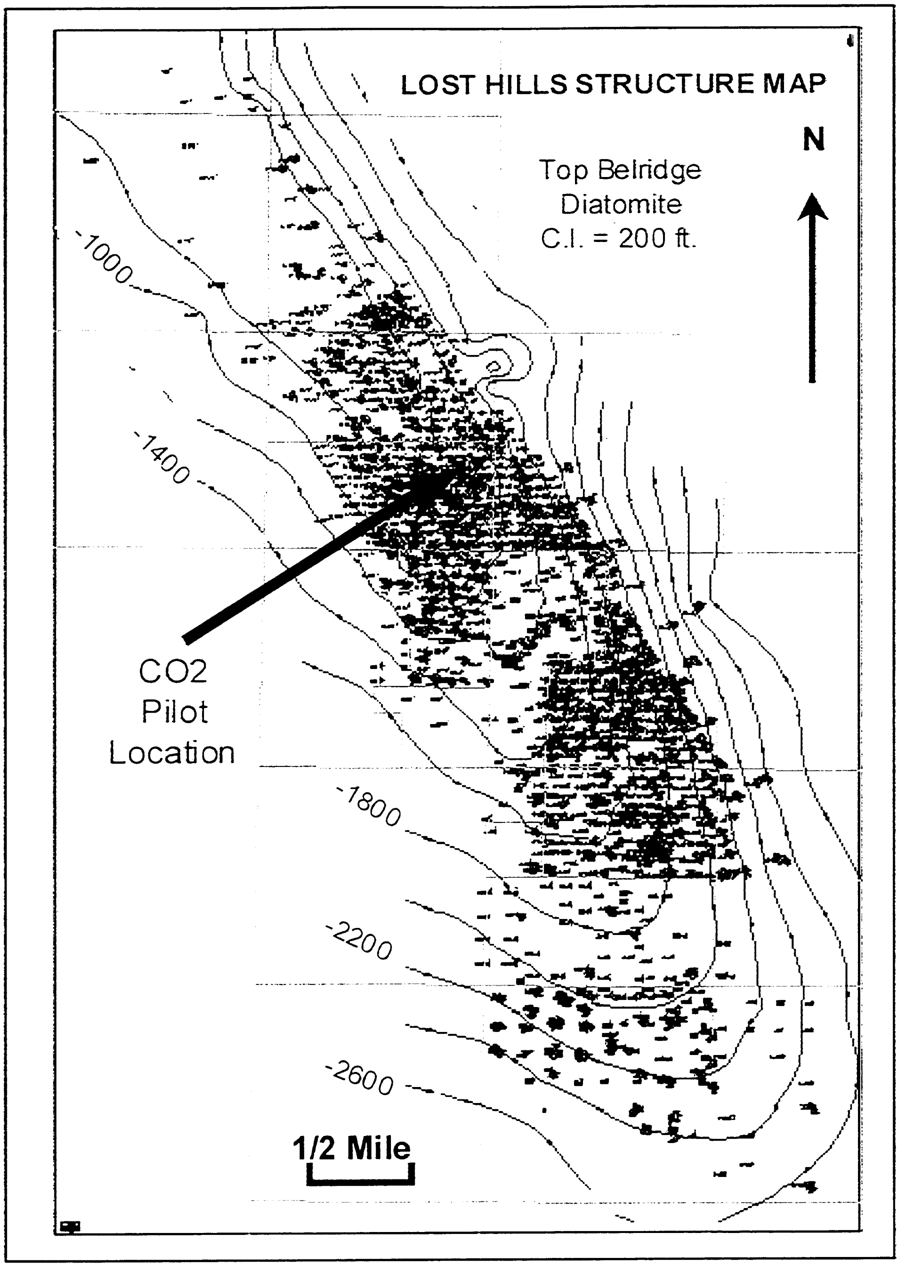



**Figure 1.1-4. Lost Hills top Belridge Diatomite structure map. Contour interval 200 feet.**

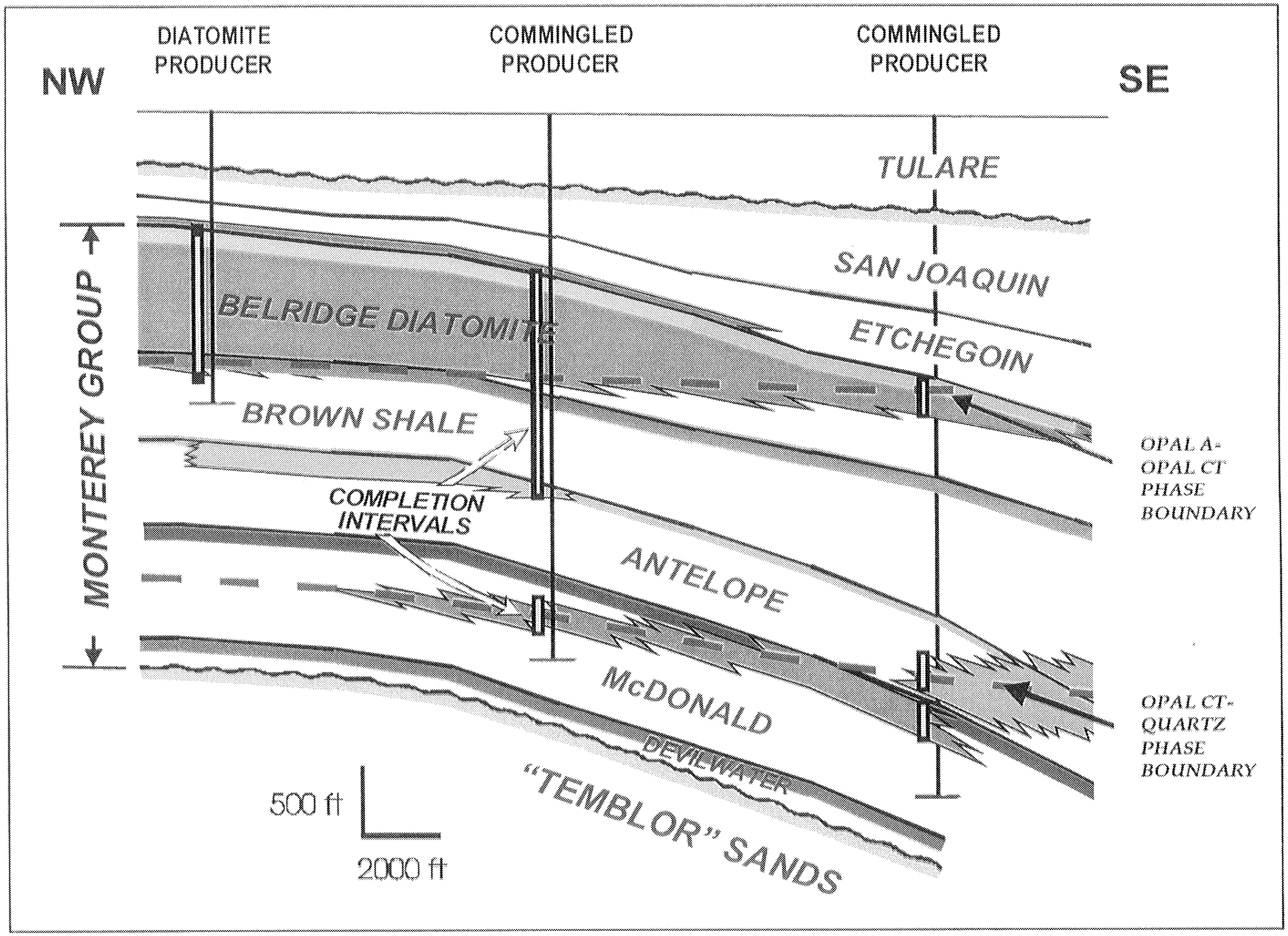



**Figure 1.1-5. Generalized cross section along southeast plunge on Lost Hills. The Belridge Diatomite is the objective of the $CO_2$ pilot project.**

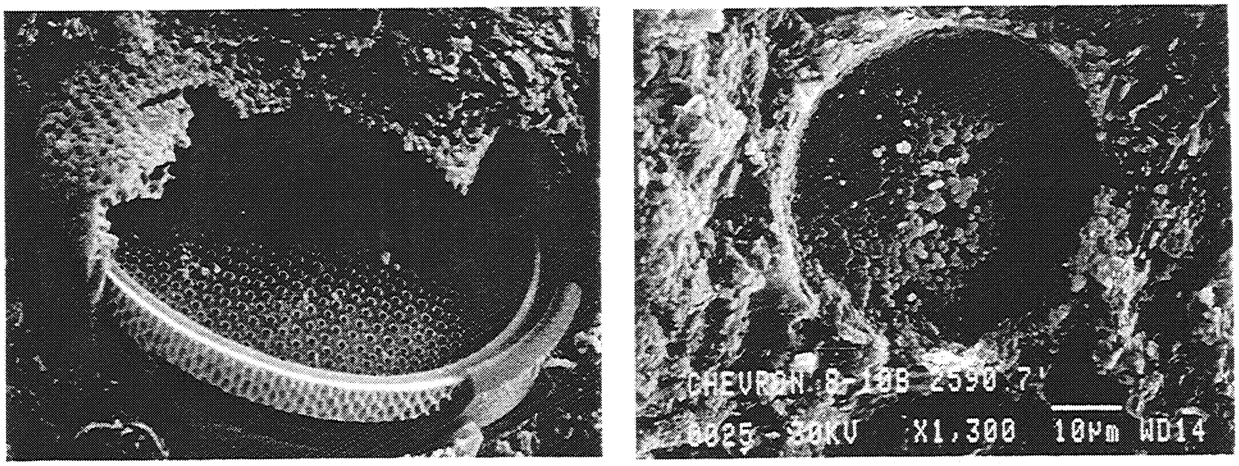



Figure 1.1-6. SEM photomicrographs of opal-A frustule starting to convert to opal-CT (left), and frustule converted to opal-CT (right). 1,300X magnification.

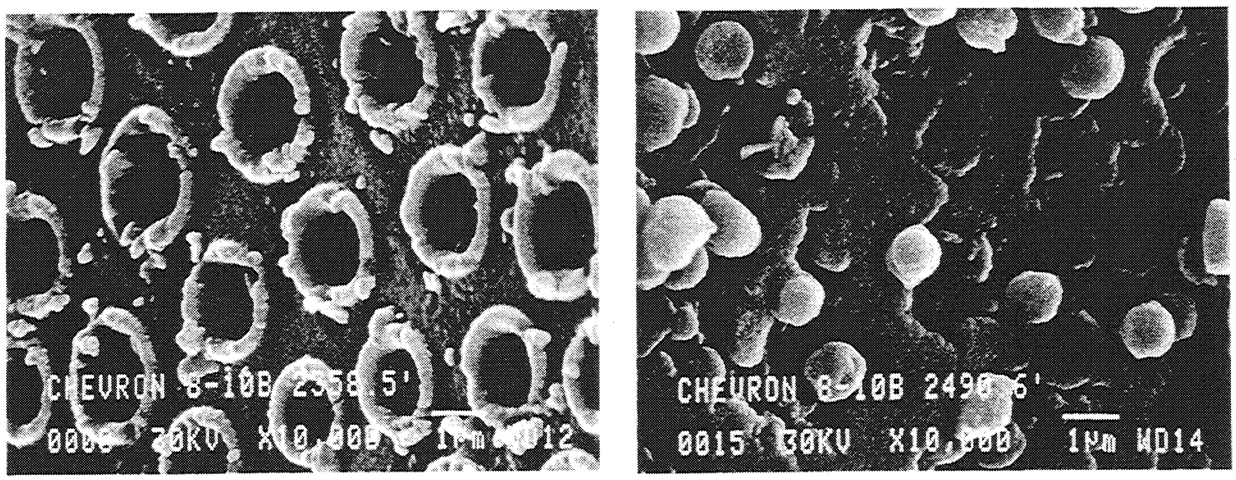



Figure 1.1-7. Opal-A frustule initiating conversion to opal-CT (left), and a frustule after its conversion to opal-CT. SEM photomicrographs, 10,000X magnification.

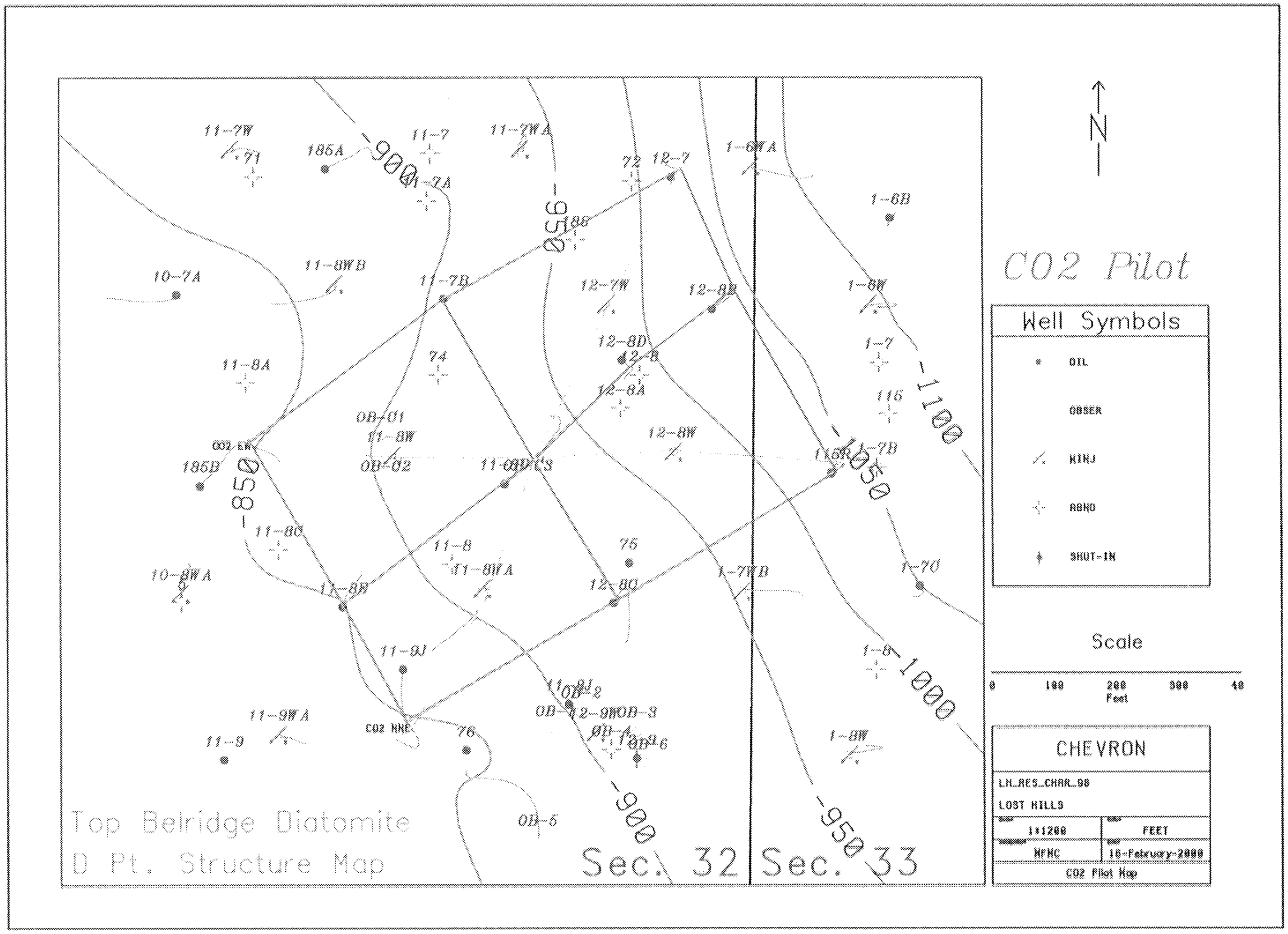



**Figure 1.1-8. Lost Hills $CO_2$ pilot base map. Structure contours on Top Belridge Diatomite.**

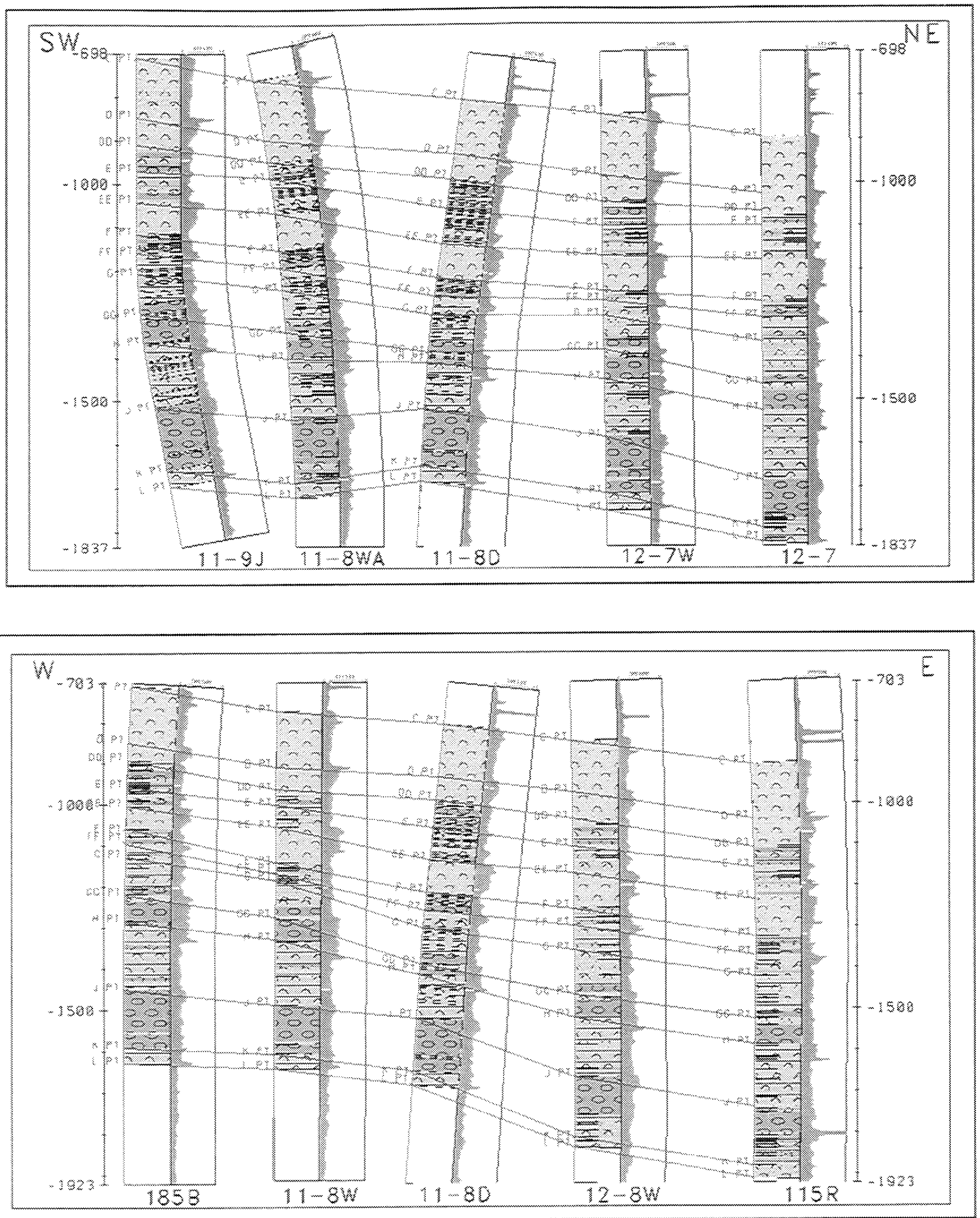



**Figure 1.1-9. Cross Sections through pilot area. $CO_2$ injection will be in the FF through L interval. Changes in interval thicknesses due to small faults. Predominant lithologies (end members) shown: "sandy" diatomite (half circles and dots), "clean" diatomite (ovals), and "clayey" diatomite (half circles).**

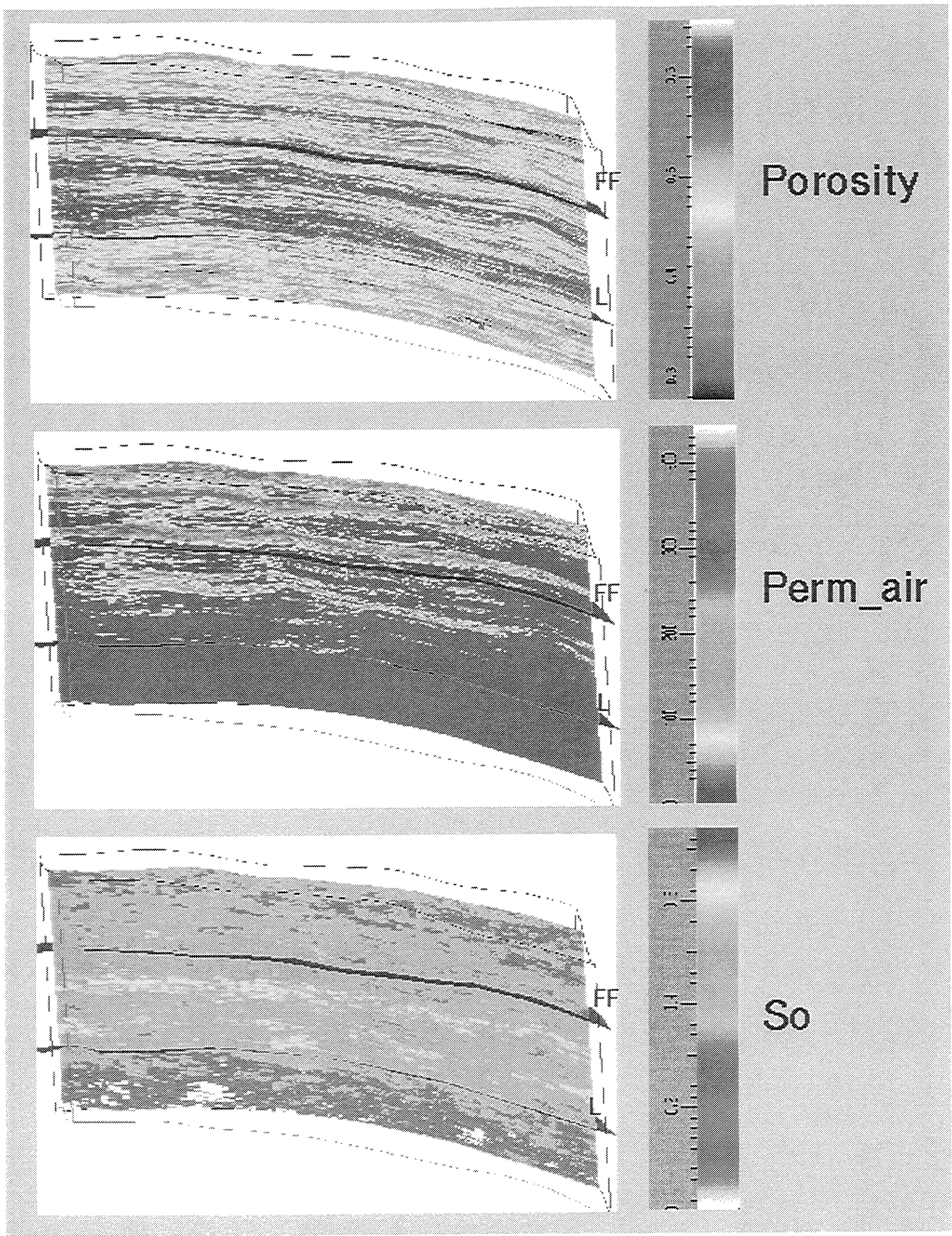
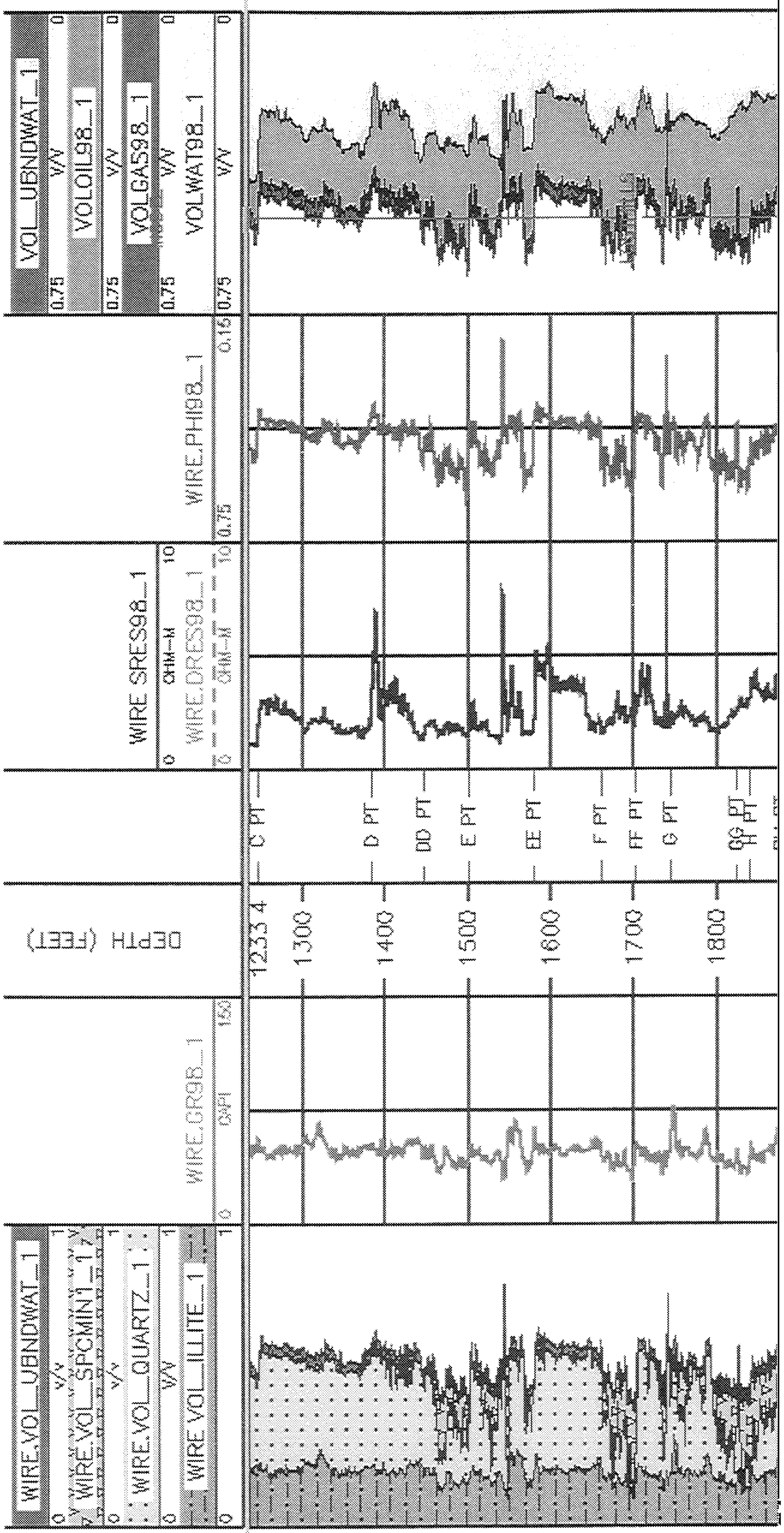



**Figure 1.1-10. Cross-sections of porosity, air permeability, and oil saturation of the C Point to Upper Brown Shale interval from W. Fong's 3D Earth Model. The view is SW-NE and the length is extends across 4 patterns (one on either side of the pilot). The proposed $CO_2$ injection interval, FF - L, is highlighted. This is the same interval as the current waterflood.**



WIRE.VOL_UBNDWAT_1
V/V
WIRE.VOL_SPCMIN1_1
WIRE.VOL_QUARTZ_1
WIRE.VOL_ILLITE_1
WIRE.GR98_1
GAPI
0
150
DEPTH (FEET)
1233.4
1300
1400
1500
1600
1700
1800
C PT
D PT
DD PT
E PT
EE PT
F PT
FF PT
G PT
GG PT
H PT
WIRE.SRES98_1
OHM-M
WIRE.DRES98_1
10
WIRE.PHI98_1
0.75
0.15
VOL_UBNDWAT_1
VOLOIL98_1
VOLGAS98_1
VOLWAT98_1

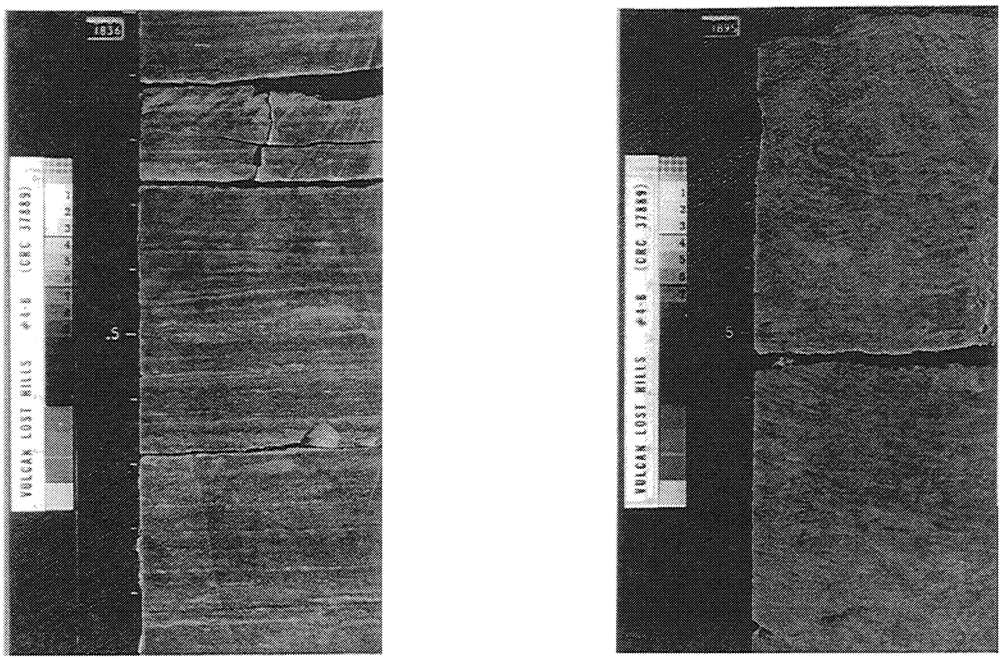


Figure 1.1-12. Slabbed core of laminated diatomite (left), and bioturbated sandy diatomite (right).

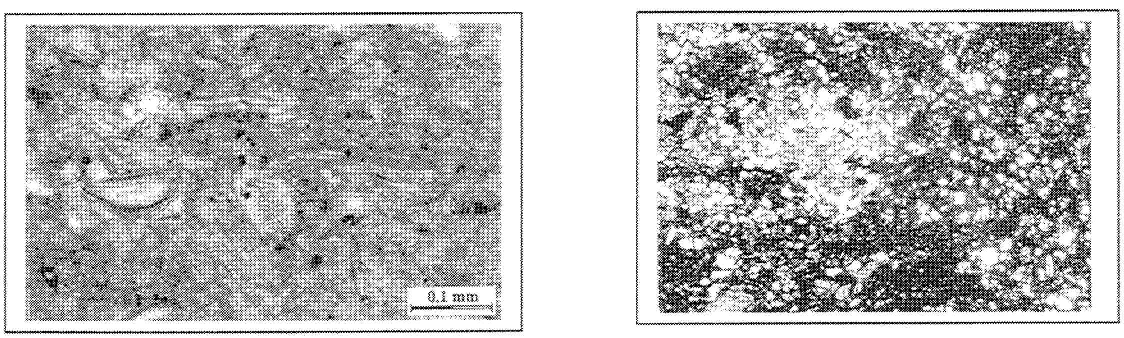



**Figure 1.1-13. Thin section photomicrographs of a "clean" diatomite from the J Unit (left; 200X) and a "sandy diatomite from the GG Unit (right; 40X, unpolarized and polarized light). The J unit thin section shows diatoms and porosity in blue. The GG Unit shows "blotchy" sand and porosity due to bioturbation.**

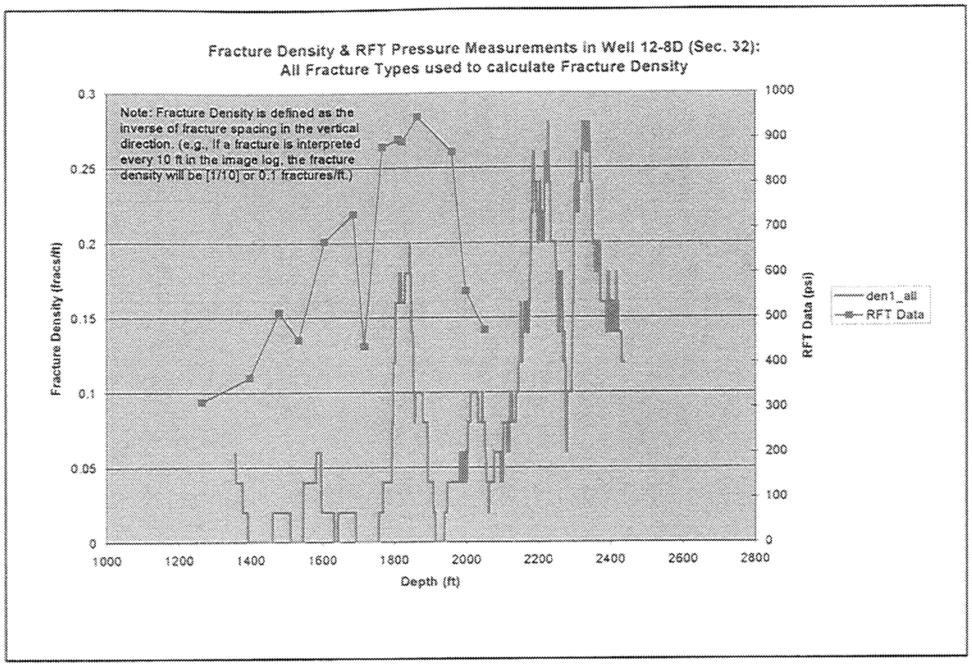



Figure 1.1-14. Halliburton Formation Tester measurements (upper curve) and fracture densities calculated from well 12-8D EMI log. Fracture data is from D. Julander.

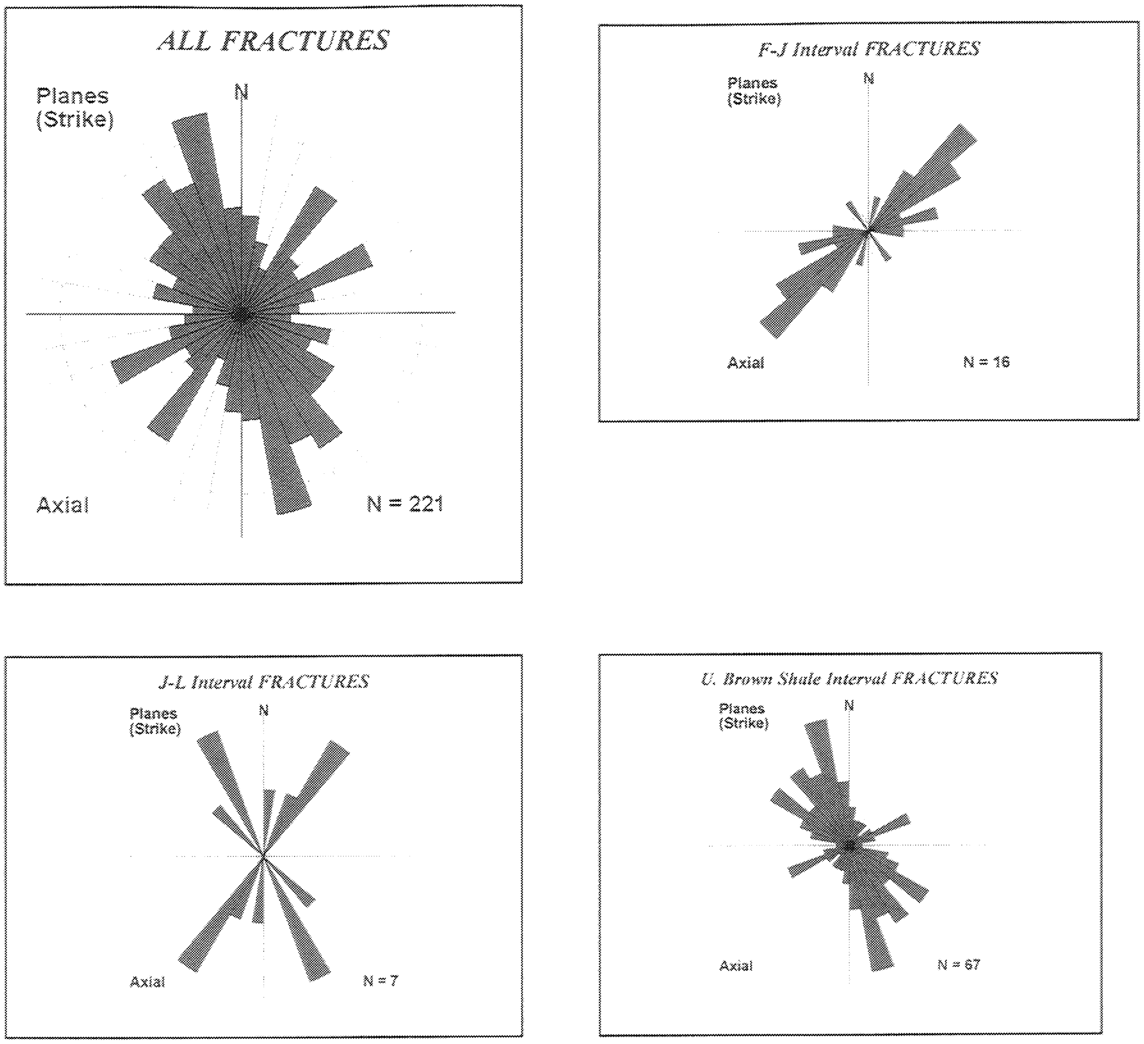



**Figure 1.1-15. Azimuths of natural fractures as measured from the OB-7 EMI log. The CO2 pilot will target the F-L interval. Note the increase in fractures and change in fracture azimuth in the Upper Brown Shale versus the F-J and J-L intervals. The OB-7 is 600 feet to the southwest of the $CO_2$ pilot. Data is from D. Julander.**

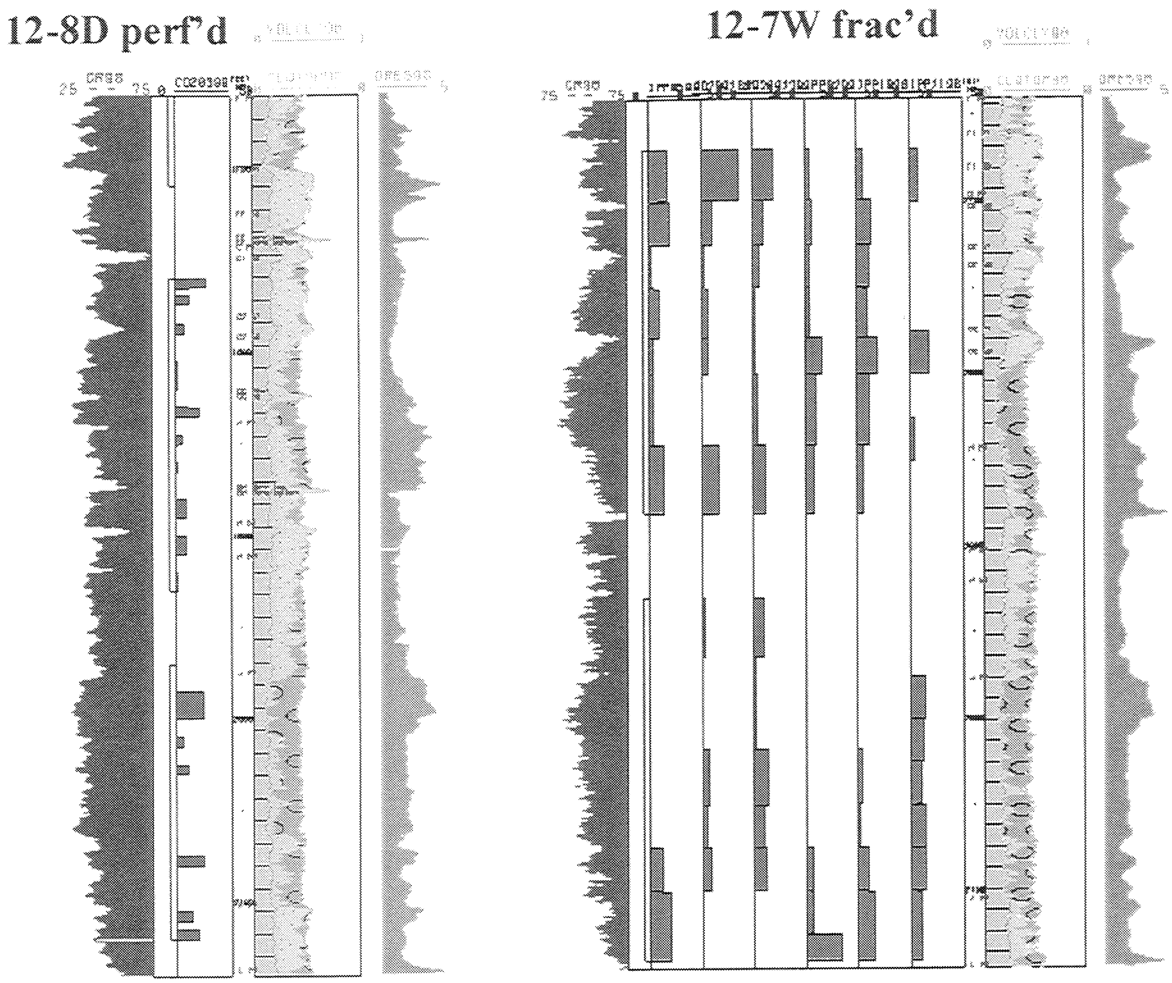



**Figure 1.1-16. $CO_2$ injection profiles for the 12-8D and 12-7W wells. The tracks represent from left to right: gamma ray (25 – 75 API units), injection profiles, lithology, and resistivity (0 –5 ohm m). The 12-8D shows the $CO_2$ injection profile (0-50%). The 12-7W shows, from left to right, profiles for water injection (after $CO_2$), two $CO_2$ profiles (higher and lower rate), and three earlier water injection profiles (1999, 1998, and 1996). The lithology track shows percentages, from left to right, of clay, sand/silt, and biogenic silica.**

## 1.2 LOST HILLS CURRENT DEVELOPMENT

**Lost Hills Primary Development:**
The Lost Hills Field, located 45 miles northwest of Bakersfield, California, (see Figure 1.2-1) was discovered in 1910. Reserves in the shallow sands, diatomite, and chert pools (Figure 1.2-2) were developed using slotted liner completion techniques until the late 1970's. From the late 1970's to 1987, small volume hydrofracture completions were performed covering the entire Belridge Diatomite.

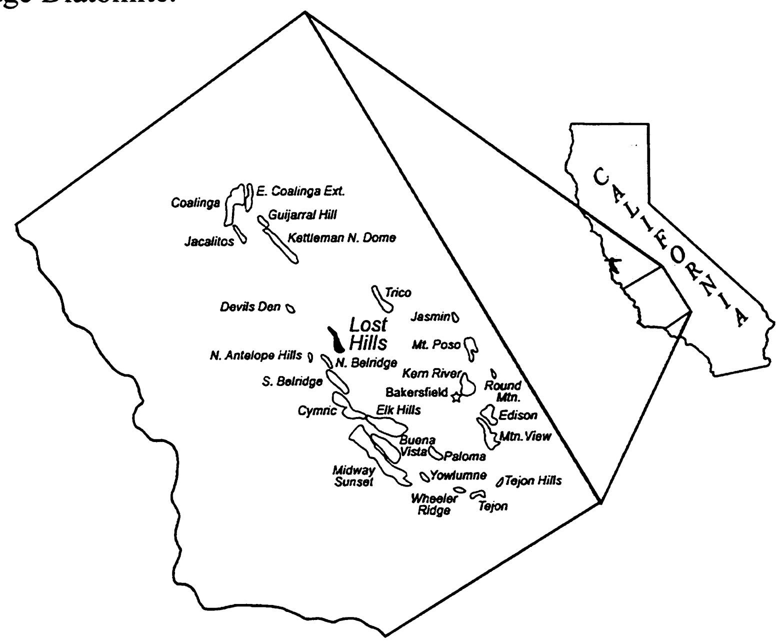



**Figure 1.2-1. Lost Hills Field Location Map.**

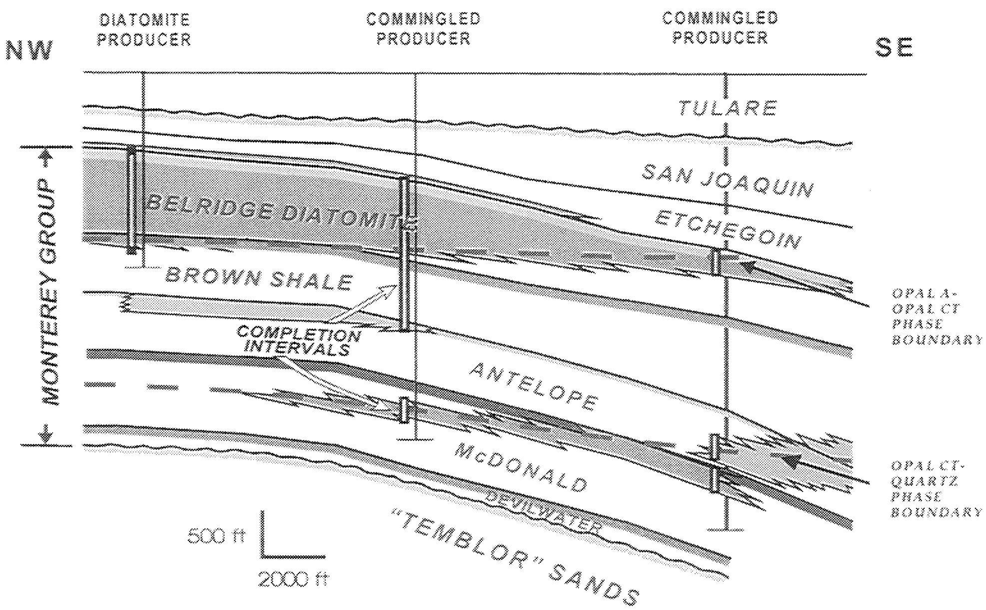



**Figure 1.2-2. Lost Hills Field Regional Cross-Section.**

Advances in hydraulic fracturing technology in the late 1980's resulted in increased oil recovery that led to a more aggressive development program by Chevron. From 1987 to the present, high volume hydrofracture completions have been performed across the entire Belridge Diatomite and the Upper Brown Shale resulting in significant production increases as shown in Figure 1.2-3. The Lost Hills Field is developed on a 5 acre (siliceous shale) to 1.25 acre (diatomite) well spacing. There are over 2.2 billion barrels of oil in place in the Belridge Diatomite in Lost Hills. To date only 112 million barrels have been produced, or approximately 5% of the original oil in place (OOIP).

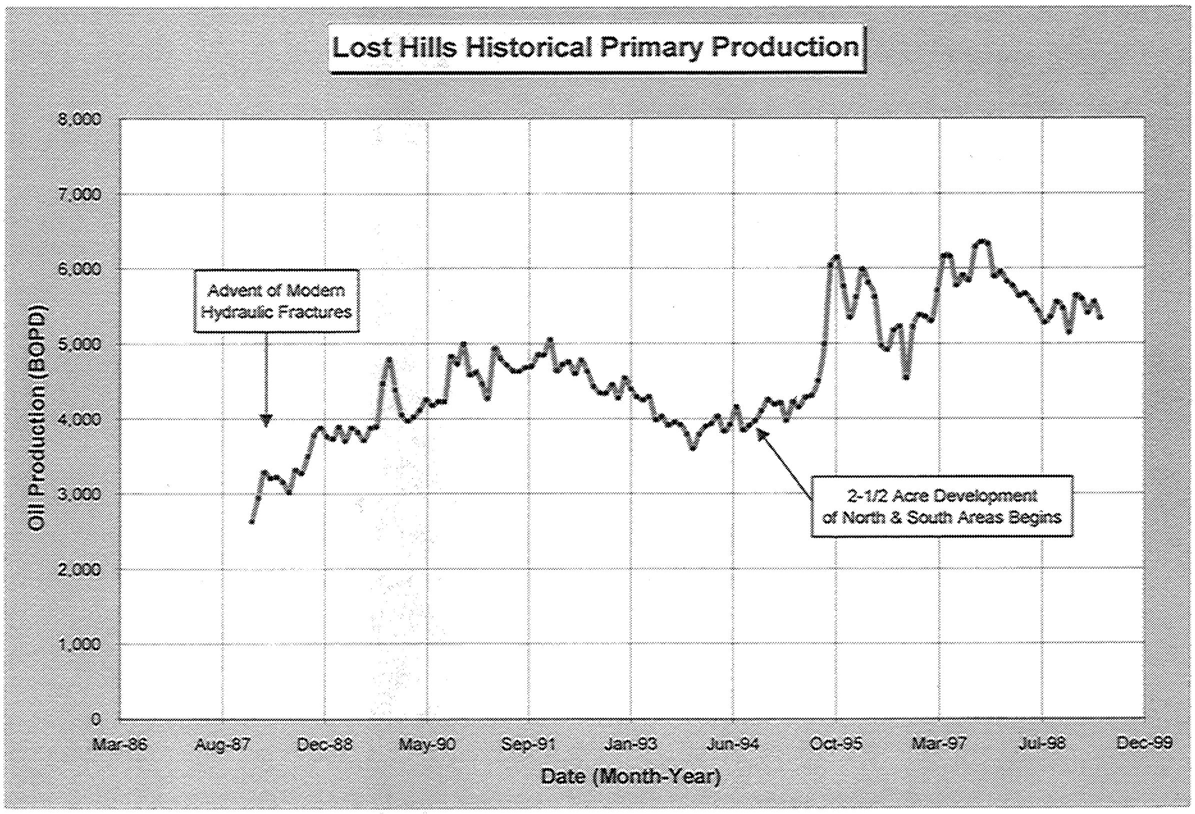



**Figure 1.2-3. Lost Hills Historical Primary Production.**

**Diatomite Waterflood Development:**

Chevron initiated a pilot diatomite waterflood project in December 1990 and began full-project development in April 1992. Since 1992, two hundred and eight 2-1/2 acre patterns have been put on water injection spanning parts of four sections (Sections 4, 5, 32 Fee, and 33) as shown in Figure 1.2-4. The historical performance of the Lost Hills waterflood performance can be seen in Figure 1.2-5. Since the initiation of first project water injection in April 1992, production has increased approximately 4,000 BOPD from 6,400 BOPD to the current rate of 10,400 BOPD.

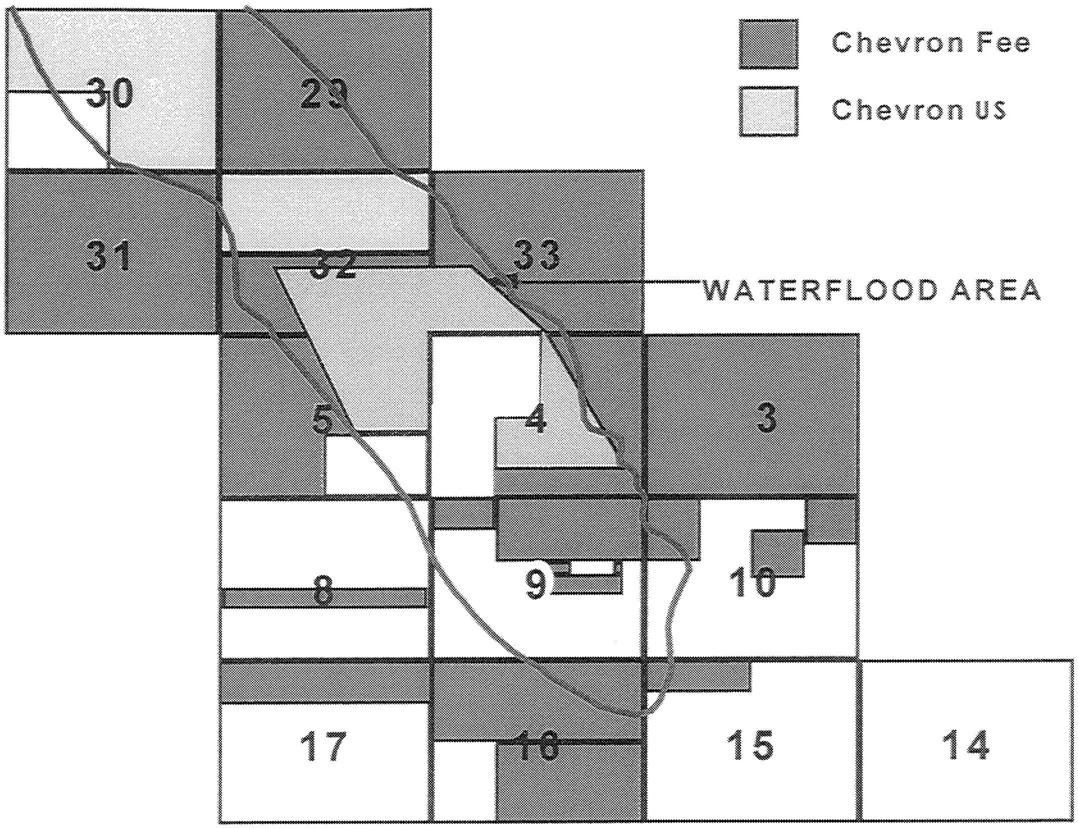



Figure 1.2-4. Lost Hills Waterflood Project Location Map.

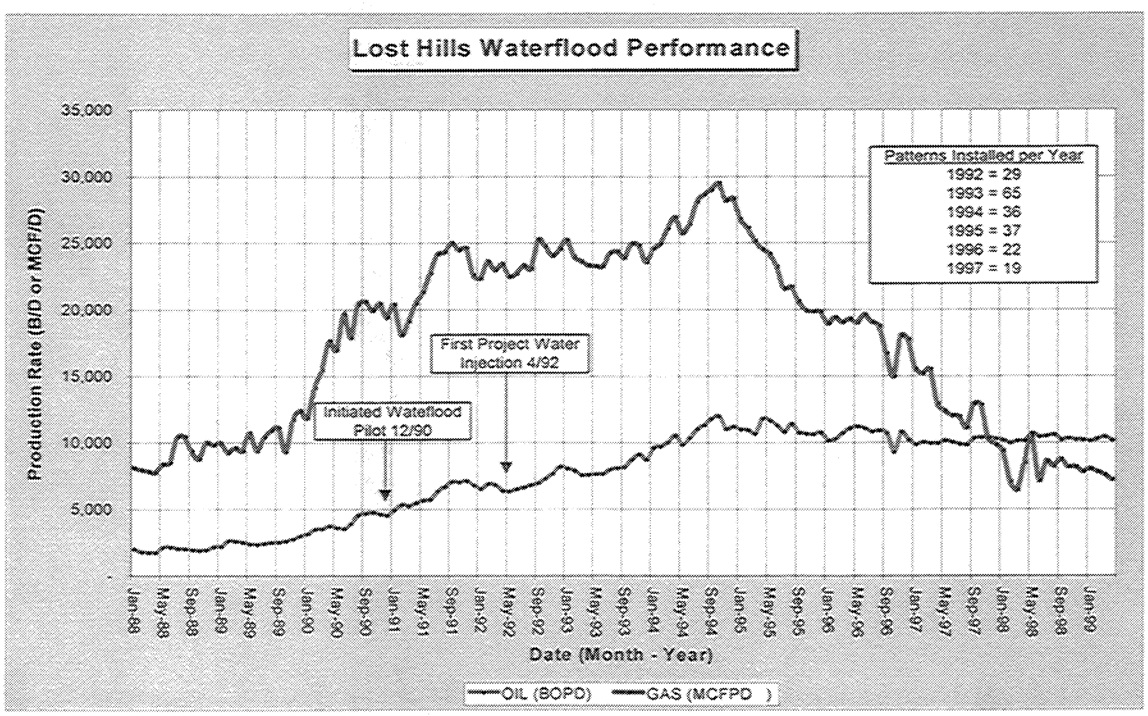



Figure 1.2-5. Lost Hills Waterflood Performance.

In terms of recovery efficiency, Figure 1.2-6 compares the estimated primary and secondary (waterflood) recoveries for each of the 4 sections under waterflood to the original Lost Hills Waterflood GO-36 on a per pattern basis. The height of the bars in Figure 1.2-6 represent the average pattern OOIP. Estimated ultimate waterflood recovery from the Lost Hills diatomite is 8.1% of OOIP, which is considerably less than the original GO-36 estimate of 19.6% of OOIP.

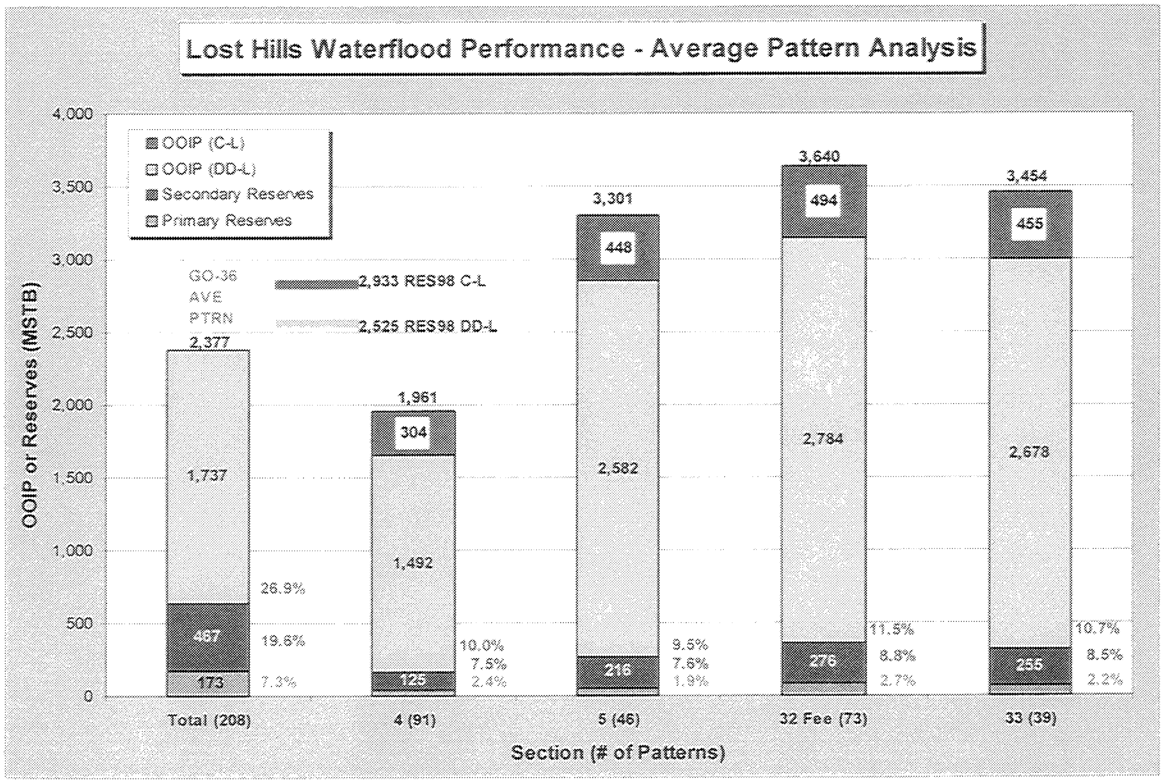



**Figure 1.2-6. Lost Hills Estimated Waterflood Reserves and Recovery Factors.**

**Infill Primary Pilot:**

An infill primary pilot was initiated by Chevron in Section 32 U.S. in 1998 to test the economic viability of improving primary recovery (3 – 4 % of OOIP to date) by infill drilling from the current 2-1/2 acre development down to 1-1/4 acre spacing. A total of 11 infill producers have been or will be drilled and completed by the conclusion of the pilot test.

**Infill Waterflood Pilot:**

Installation of an infill waterflood pilot began in late 1998 by Chevron in Section 32 Fee to test the potential of waterflooding with 1-1/4 acre "direct line-drive" patterns compared to the current 2-1/2 acre "staggered" patterns. Plans call for 17 wells (6 injectors and 11 producers) to be drilled to determine if the current waterflood recovery can be accelerated, or better yet, if incremental waterflood reserves can be obtained by infill drilling.

**Diatomite Steamflood Pilot:**
Chevron initiated a diatomite steamflood/cyclic steam pilot in the southern portion of Section 29 in October 1998. The steamflood pilot consists of 7 injectors targeting the J – L "clean" diatomite intervals. A single pattern cyclic steam pilot consisting of 4 producers targeting the more permeable EE – F "sandy" diatomite was initiated concurrently. Both pilots are still under evaluation.

**Horizontal Wells:**
In 1997 Chevron began experimenting with horizontal wells to try to exploit the flanks of the field where vertical wells could not be economically justified due to the reduced oil column. Through September 1999, four horizontal wells have been drilled with mixed results. Figure 1.2-7 is a summary of the Lost Hills horizontal well performance to date.

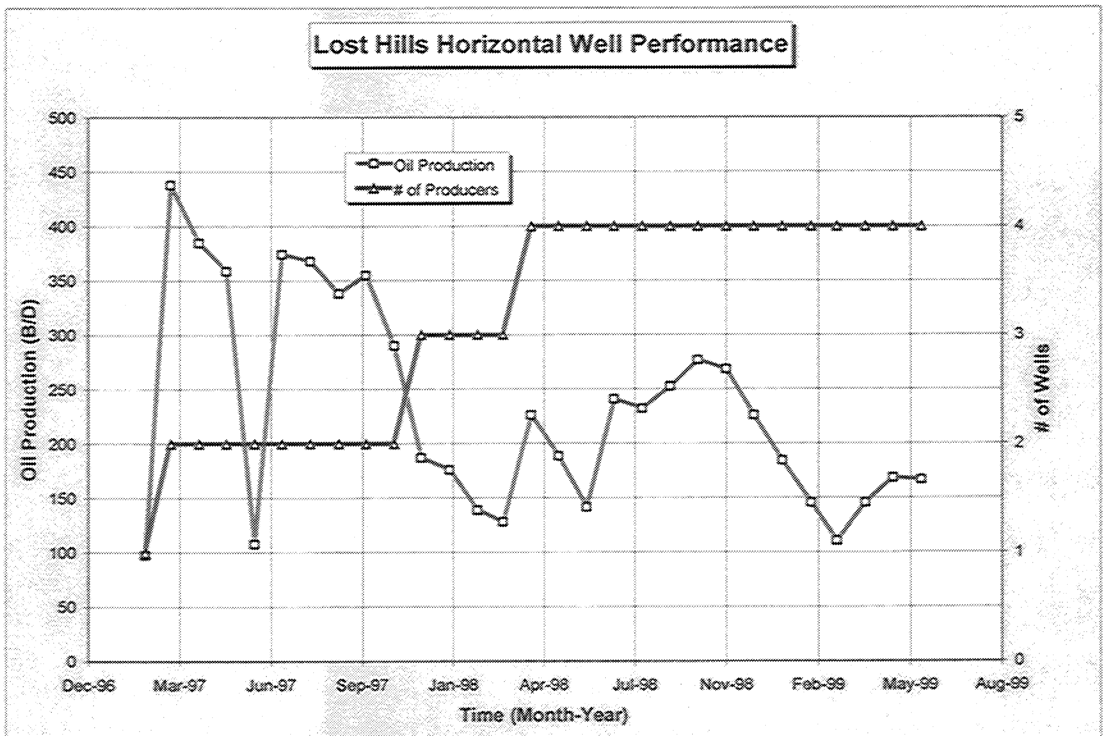



**Figure 1.2-7. Lost Hills Horizontal Well Performance.**

SECTION 2.

# PROPOSAL

## 2.1 $CO_2$ PILOT LOCATION

The proposed $CO_2$ Pilot will be located in the southeast quarter-section of Section 32, T.26S., R.21E. of the Lost Hills Field as shown in Figure 2.1-1. Plans are to install a four-pattern pilot. The pilot area is enlarged in Figure 2.1-2 showing the four existing waterflood patterns (10-8WA, 11-8WA, 12-7W, and 12-8W) which will be converted to $CO_2$ injection.

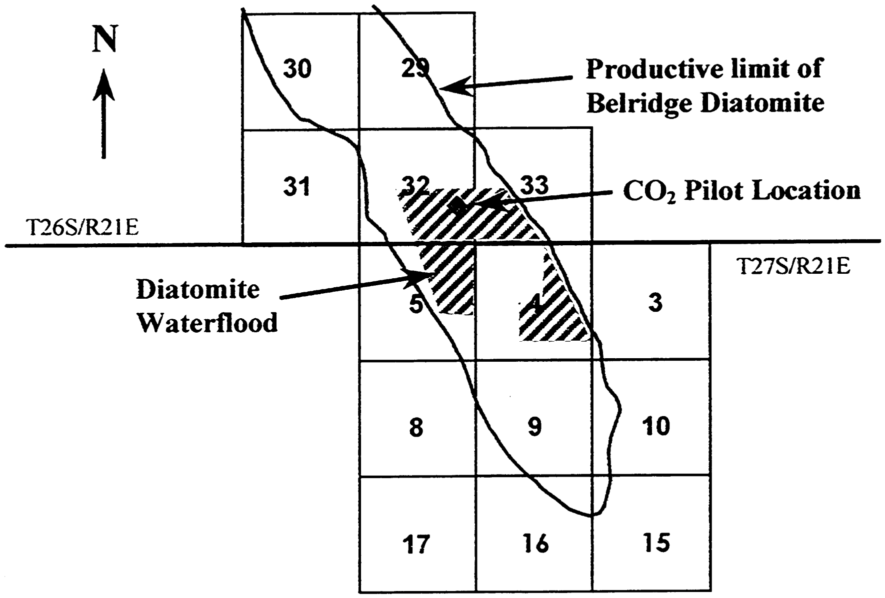



**Figure 2.1-1. Lost Hills $CO_2$ Pilot Location Map.**

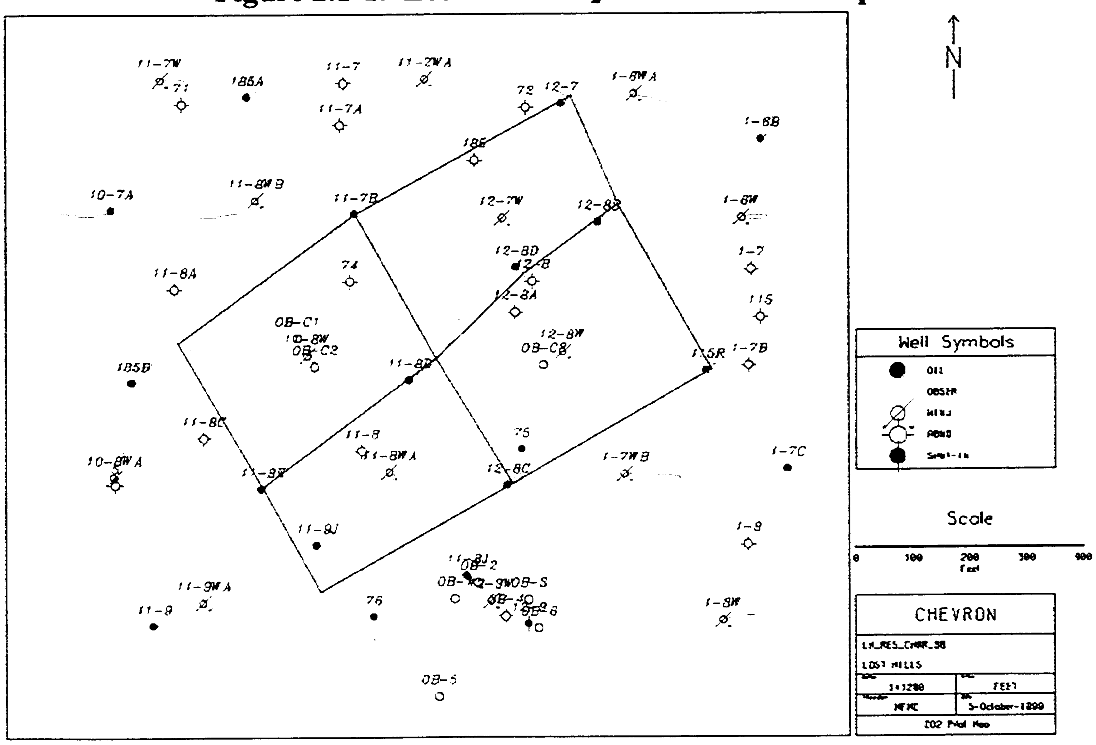



**Figure 2.1-2. Lost Hills $CO_2$ Pilot Pattern Map.**

## 2.2 $CO_2$ INJECTIVITY TEST AND RESULTS

$CO_2$ injectivity tests were conducted in the Belridge Diatomite of the Monterey Formation in the Lost Hills Field from March 11, 1999 through April 16, 1999. The injection tests took place in two wells (Figure 2.2-1). The first well, 12-8D Section 32, is a new well that was drilled during late December 1998. This well had not been completed prior to the $CO_2$ injection test. The second well, 12-7W Section 32, is a waterflood injection well that was hydraulically propped fractured during mid-1996 and has been on continuous water injection since November 1996. A total of approximately 10 MMSCF of $CO_2$ was injected during the test. Figure 2.2-2 shows the injection rate and duration of the test.

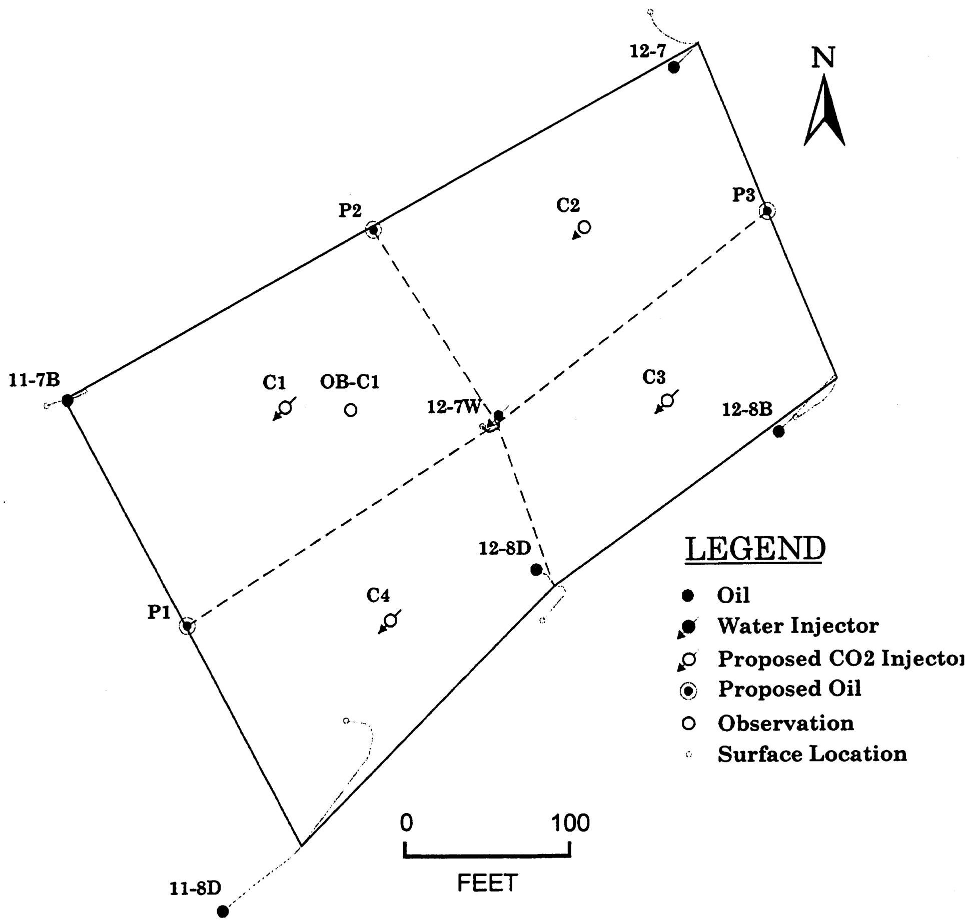



**Figure 2.2-1. Lost Hills $CO_2$ Pilot well location map. Injectivity tests were performed in 12-8D (non-hydraulically fractured well) and 12-7W (hydraulically fractured water injector). The map shows a preliminary 0.625 acre pilot design.**

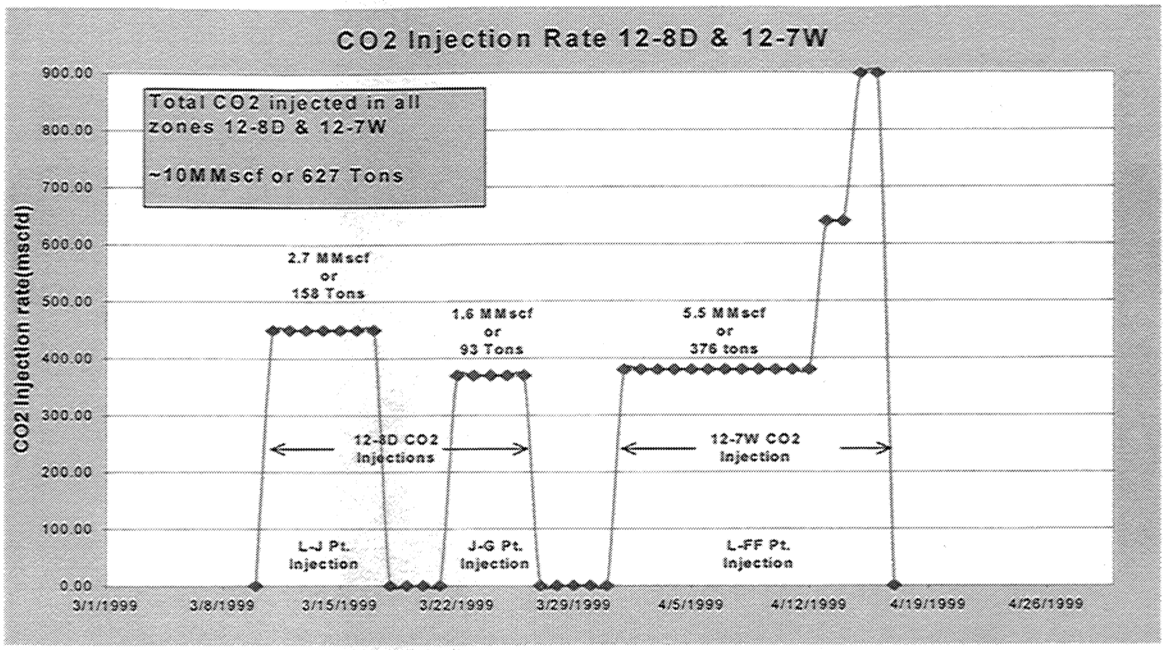



**Figure 2.2-2. Injection versus time in the 12-8D and 12-7W wells.**

**Production Response:**

Production from the 4 pattern producers (11-7B, 11-8D, 12-7, 12-8B) prior to the initiation of $CO_2$ injection was approximately 230 BOPD and 380 BWPD. Post $CO_2$ pattern production increased to a peak of 260 BOPD and 500 BWPD. Gas production rates were essentially unchanged as a result of the injection test. Figure 2.2-3 shows the gain in oil production that occurred as a result of $CO_2$ injection.

Oil production from 12-8D, was not included as part of the total pattern production. After injecting $CO_2$ in 12-8D, the well was hydraulically propped fractured and placed on production. Figure 2.2-4 contains the production history of 12-8D.

**Surface Titlmeter Mapping Results:**

Surface tiltmeter mapping has been utilized in the Lost Hills field for over 10 years. There have been approximately 300 hydraulic fractures mapped during this time indicating an average fracture azimuth of N47°E ±10°. A surface tiltmeter array was employed during all $CO_2$ injections as well as during the hydraulic propped fracture treatment of well 12-8D. The tiltmeters saw strong signals. However, the tilt vector patterns induced by the $CO_2$ injections were quite complex, indicating a more complicated fracture geometry then just a single vertical fracture. For all of the $CO_2$ injections, the surface deformation tended to have a bowl shaped pattern, indicating multiple near-vertical fractures at azimuths very different from the field average. This bowl shaped surface deformation is quite different than that of a horizontal fracture.

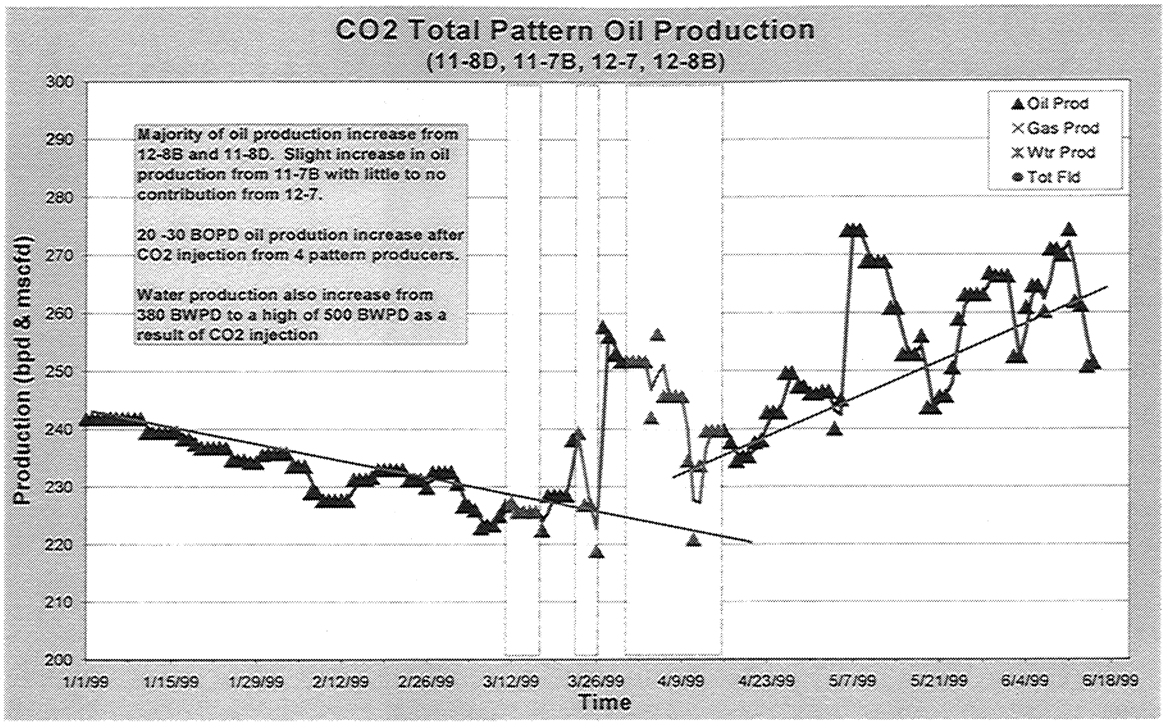



Figure 2.2-3. Gain in oil production due to $CO_2$ injection.

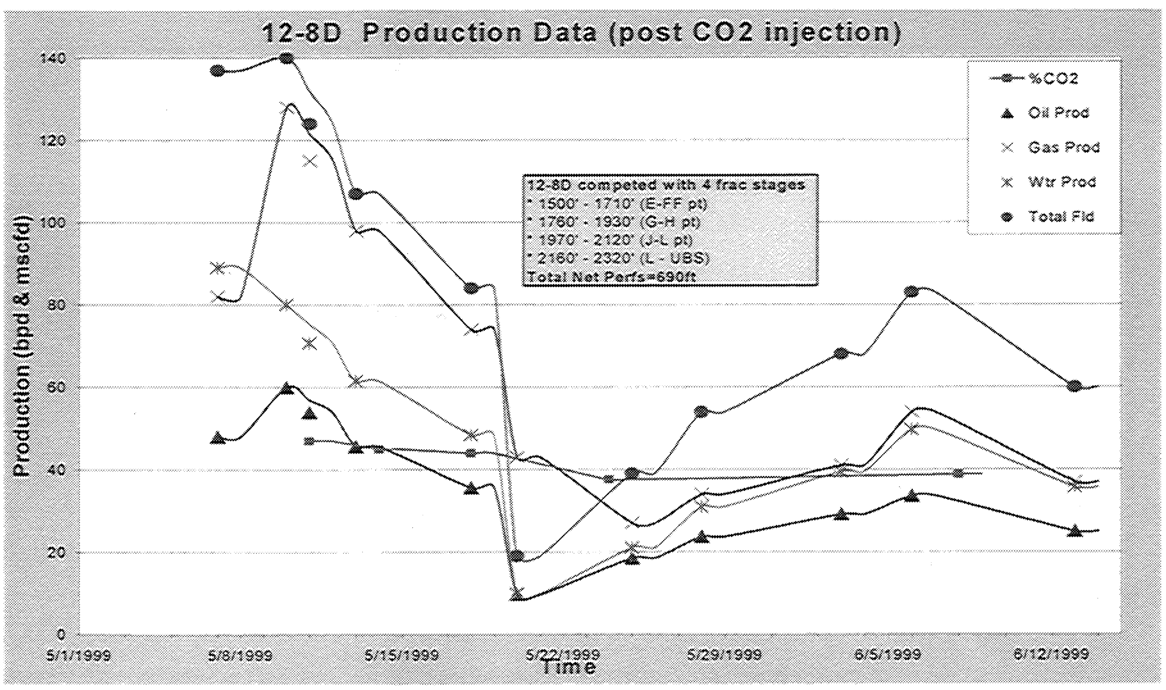



Figure 2.2-4. Post $CO_2$ production data from 12-8D.

In well 12-8D the average propped hydraulic fracture azimuth was N69°E ±6°. This possibly indicates a local reorientation of the stress field. For the two $CO_2$ injection tests in 12-8D, and the first half of the $CO_2$ injection test in 12-7W, most of the injection resulted in two fractures. Of these two main fractures, the bulk of the fluid created fractures with an average azimuth of N30°E ± 7°. That is an average rotation of about ~~than~~ 40° to the North from the hydraulically propped fractures mapped in 12-8D. The majority of the remaining injected volume created either vertical or steeply dipping fractures that were oriented N67°W ± 10° and orthogonal to the main fracture system.

From Figure 2.2-5, it is clear that there was a strong possibility for the $CO_2$ from the 12-7W to communicate with adjacent wells 11-8D and 12-7. Gas analysis data confirmed that $CO_2$ was detected in both of these wells.

The second half of the 12-7W $CO_2$ injection was significantly different from the first half. After about 8 ½ days (half-way into the injection), all of the tiltmeters dramatically changed slope, with the biggest change seen on the East side of the well. It appears that after 8 ½ - 9 days, two events happened that might possibly be related. First, the main fracture from the first half of the injection communicated with well 12-7, as both the gas production and $CO_2$ concentration increased from a baseline of 20 MSCF/D at 20% $CO_2$ to nearly 50 MSCF/D at 45% $CO_2$ concentration. Once this primary fracture was in a "steady-state", the tiltmeters no longer detected significant growth in this fracture plane. Second, an orthogonal fracture began growing that is best fit with a single vertical fracture oriented at N40°W ± 10°.

Tables 2.2-1 and 2.2-2 show the final results of the tiltmeter fracture mapping. Although the fracture system is difficult to completely resolve, the $CO_2$ injections certainly created more than a single vertical fracture. While most of the fluid was injected into vertical fractures oriented at or near N30°E, there were also significant secondary fractures (also near-vertical fractures) at very different azimuth orientations, horizontal fracture components, and very likely significant shear slippage in the formation as well.

$CO_2$ injection is not likely to be maintained with simple reservoir matrix flow, as the rates will have to be extremely low. Nor is it likely to induce simple vertical fracture growth along the Lost Hills average maximum horizontal stress direction (N50°E). Instead, injection will induce a more complicated, but not random, fracture system.

**$CO_2$ Injection Profiling:**

Injection profiling was done on each $CO_2$ injectivity test for well 12-8D prior to the well being hydraulically fractured. Additionally, $CO_2$ injection profiling was done at two 2 different injection rates during the injection test into well 12-7W which was previously hydraulically propped fractured and on water injection since 1996. Figure 2.2-6 shows a fairly even distribution of $CO_2$ for both injection intervals in well 12-8D. It appears that $CO_2$ did not flow preferentially into zones of higher permeability.

Inasmuch as well 12-7W had been on water injection prior to $CO_2$ injection, a good comparison of water vs. $CO_2$ injection can be seen in Figure 2.2-7. Injection profiles indicate $CO_2$ entered zones where water injection was minimal.

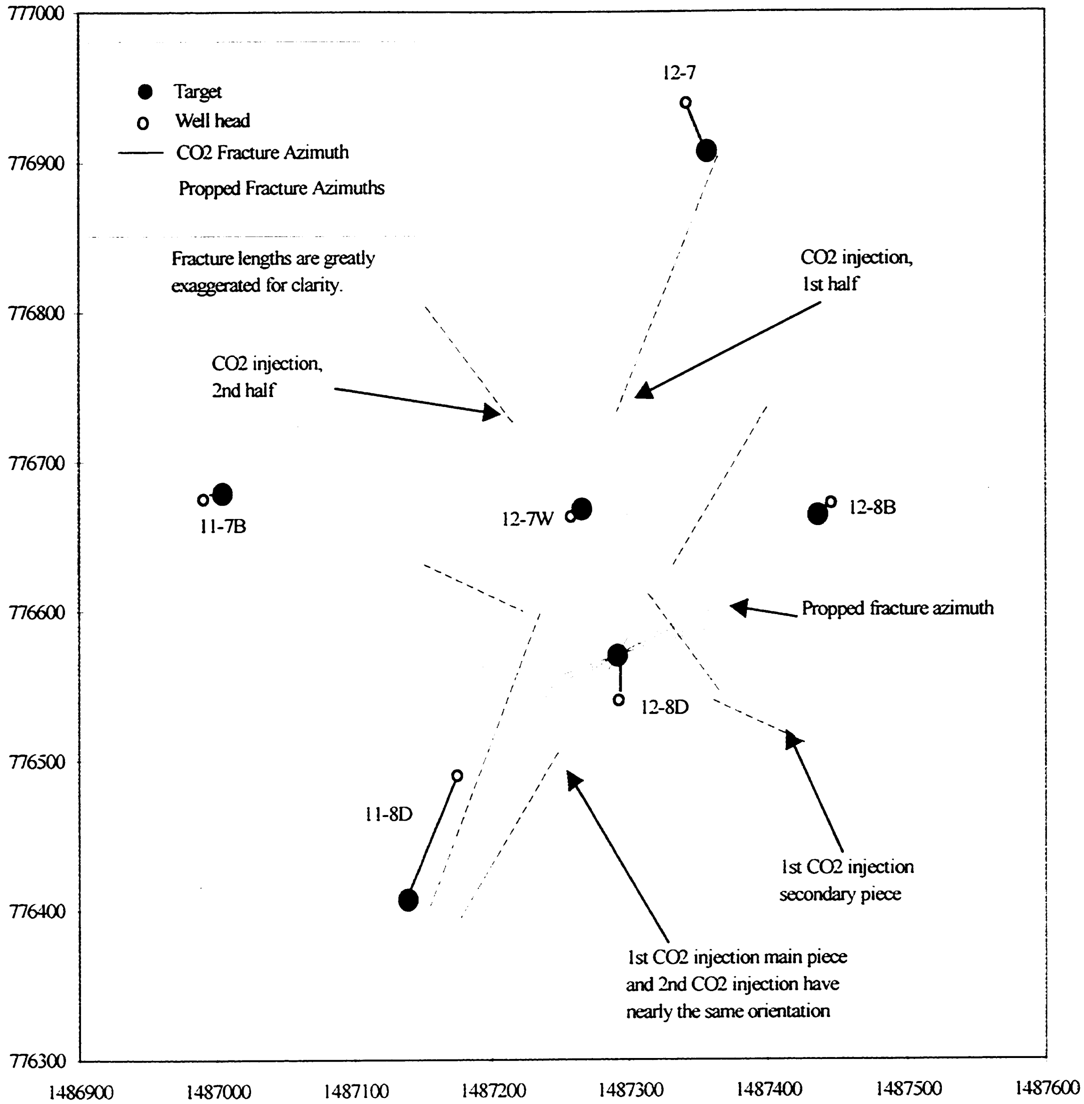



**Figure 2.2-5. Map showing hydraulically propped fracture azimuths from tiltmeter analysis.**

**Table 2.2-1. Tiltmeter fracture mapping results for $CO_2$ injections in Wells 12-8D and 12-7W.**

| Well | Inj. | Date | Volume Liquid Equiv. $CO_2$ (BBL) | Average Injection Rate Liquid Equiv. $CO_2$ (bpd) | Perf Interval (ft) | Azimuth | Dip | Volume % Component |
|---|---|---|---|---|---|---|---|---|
| 12-8D | Inj. 1 | 3/10/99-3/17/99 | 867 | 123.85 | 1970-2120 | N 32° E ± 8° | 82° ± 6° down to the NW | 55% |
| | | | | | | N 67° W ± 10° | 84° ± 7° down to the SW | 45% |
| 12-8D | Inj. 2 | 3/22/99-3/26/99 | 511 | 127.75 | 1760-1930 | N 34° E ± 7° | 84° ± 5° down to the NW | 75% |
| | | | | | | N 64° W ± 10° | Steeply dipping | 25% |
| 12-7W | Inj. 1 First Half | 3/31/99-4/8/99 | 1027 | 120.8 | 1670-2140 | N 23° E ± 7° | 89° ± 6° down to the SE | 75% |
| | | | | | | N 69° W ± 10° | Steeply dipping | 25% |
| 12-7W | Inj. 1 Second Half | 4/8/99-4/16/99 | 1027 | 120.8 | 1670-2140 | N 40° W ± 10° | 80° ± 10° down to the SW | N/A* |

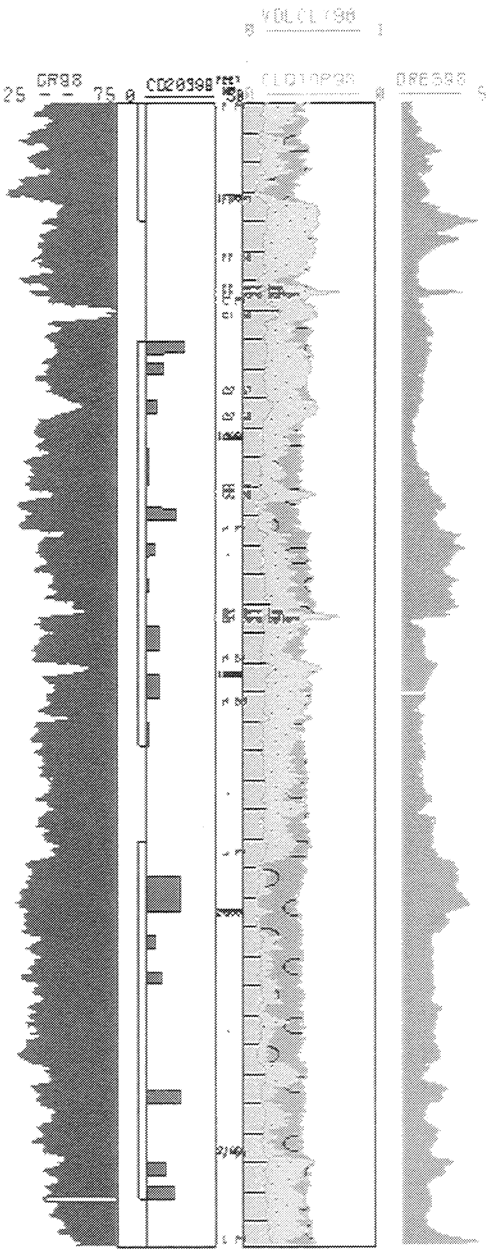
* This fracture has a significant shear displacement component

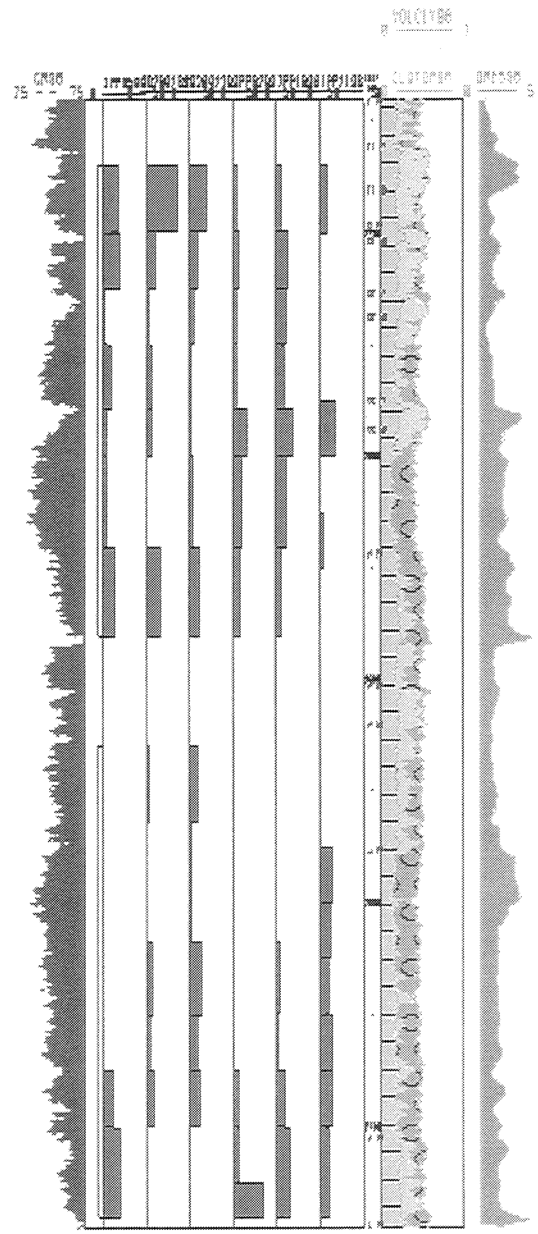
**Table 2.2-2. Tiltmeter fracture mapping results for propped fracture treatments in Well 12-8D.**

| Well | Stage | Date | Volume (BBL) | Perf Interval (ft) | Azimuth | Dip | Volume % Horizontal Component |
|---|---|---|---|---|---|---|---|
| 12-8D | 1 | 4/28/99 | 660 | 2160-2320 | N 62° E ± 5° | 74° ± 4° down to the NW | 39%** |
| 12-8D | 2 | 4/30/99 | 152 | 1970-2120 | N 66° E ± 6° | 70° ± 5° down to the NW | 36%** |
| 12-8D | 3 | 4/30/99 | 812 | 1760-1930 | N 72° E ± 4° | 87° ± 3° down to the NW | 56%** |
| 12-8D | 4 | 4/30/99 | 778 | 1500-1710 | N 75° E ± 4° | 75° ± 5° down to the SE | 24%** |

## 12-8D Peforated

## 12-7W Fractured





**Figures: 2.2-6 and 2.2-7. Injection profile from $CO_2$ injection (pink bars) into 12-8D prior to prop fracture, shows fairly even distribution with no preference for $CO_2$ to enter into higher perm zones. $CO_2$ profiling from 12-7W shows $CO_2$ (pink bars) entering into zones not well covered by water injection (blue bars). 12-7W injection profiles in chronological order from right to left.**

## 2.3 $CO_2$ PILOT EARTH MODEL

This section discusses the construction of a detailed earth model around the $CO_2$ pilot area at Lost Hills. The objective is to use the earth model to construct a reservoir flow simulation model in order to predict and analyze the future $CO_2$ pilot performance.

A detailed, full-field, reservoir characterization effort was completed last year by Chevron. Using this new data allows us to build better geologic models. Past simulation models were based on small, single pattern models with rather idealized fracture geometry. Although they have been adjusted to match averaged historical production, these models have significant confinement problems. A model covering a larger area has less confinement problems, and can better capture heterogeneity and fracture interference. In addition, an area-specific model is needed to carefully match the historical production (primary depletion and waterflood to date) in the pilot area.

**Model Framework:**
Chevron's G2/Gocad++ software was used in most of the earth modeling steps. The model covers 16 injector-centered patterns, as shown in Figure 2.3-1. The $CO_2$ pilot consists of the center four patterns. A 149-well group around the pilot area was extracted from the full field data. A total of 17 surfaces from the C-Pt. to 300 feet below the L-Pt. were used to confine the model, as listed in Figure 2.3-2. The total reservoir thickness is 1176'. The earth model has 25' × 5' areal grids, and 500 layers each about 2' thick. This results in a 10.3 MM grid model.

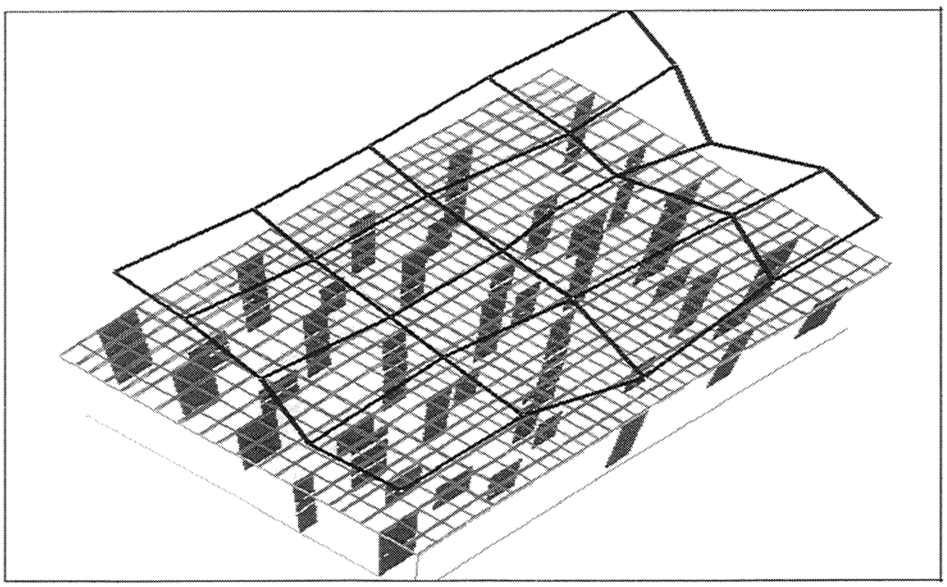


**Figure 2.3-1. 16 pattern model outline. Pilot is in center 4 patterns.**

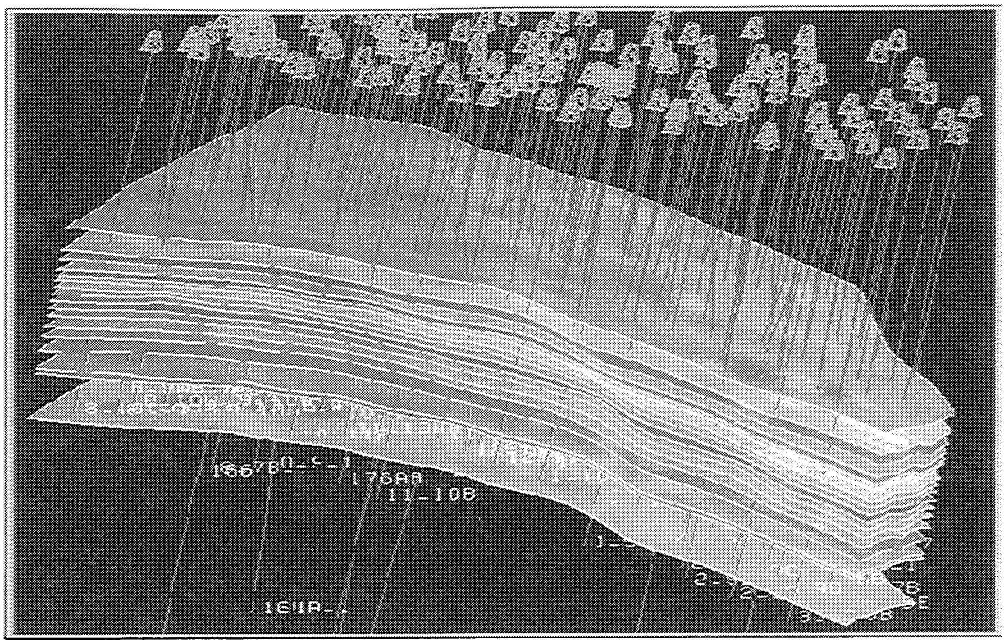


**Figure 2.3-2. Wells and 17 marker surfaces used in model construction.**

Table 2.3-1 lists the marker surfaces incorporated in the model, and averaged properties for each layer. The total OOIP of this model is 73 MMSTB, including the 300' interval below the L-Pt.

**Table 2.3-1. Markers and average interval properties.**

| Marker name | Avg. thickness (ft) | Avg. Porosity % | Avg. Air Perm (md) | Average $S_o$ (%) |
|---|---|---|---|---|
| C-Pt. | 127 | 44.4 | 8.5 | 30.7 |
| D-Pt. | 58 | 45.2 | 9.8 | 39.0 |
| DD-Pt. | 59 | 53.2 | 3.1 | 40.4 |
| E-Pt. | 36 | 50.7 | 3.1 | 40.1 |
| E2 Sand Top | 32 | 49.6 | 5.6 | 44.1 |
| EE Top | 55 | 46.3 | 7.4 | 44.8 |
| F-Pt. | 38 | 52.3 | 3.6 | 47.1 |
| FF-Pt. | 42 | 50.5 | 3.2 | 45.4 |
| G-Pt. | 48 | 49.4 | 2.9 | 44.2 |
| G2 Sand Top | 50 | 52.7 | 2.9 | 48.6 |
| GG-Pt. | 57 | 58.4 | 3.6 | 56.3 |
| H-Pt. | 56 | 51.3 | 3.6 | 50.8 |
| H Sand Top | 71 | 52.0 | 2.0 | 47.8 |
| J-Pt. | 81 | 54.0 | 1.6 | 49.4 |
| K-Pt. | 69 | 47.7 | 1.5 | 41.5 |
| L-Pt. – 300' Below | 300 | 43.2 | 0.53 | 24.9 |
| Total or Average | 1176 | 49.6 | 4.4 | 43.8 |

**Geostatistics:**
To populate the 3D volume, geostatistics was applied. A set of three logs, (PERM98, SO98 and PHI98) from the 149 wells, which correspond to calculated air permeability, oil saturation and porosity, respectively, were analyzed. Nested variograms can fit the data quite well. As shown in Table 2.3-2, each property can be modeled as a two level nested variogram. Model 1 is the short range, and Model 2 is the long range fit in feet. The Z, or vertical, range is normalized to the entire interval.

**Table 2.3-2. Variogram Ranges**

| | X Range(ft) | Y Range (ft) | Z Range (ft) | Azimuth (degrees) |
|---|---|---|---|---|
| **Oil Saturation** | | | | |
| Model 1 - Exponential | 139 | 112 | 0.029 | 132 |
| Model 2 – Gaussian | 10000 | 6500 | 0.24 | 149 |
| | | | | |
| **Porosity** | | | | |
| Model 1 – Exponential | 374 | 284 | 0.019 | 149 |
| Model 2 – Exponential | 15000 | 7500 | 0.187 | 121 |
| | | | | |
| **Ln of Permeability** | | | | |
| Model 1 – Exponential | 327 | 249 | 0.025 | 19 |
| Model 2 – Gaussian | 20000 | 10000 | 0.63 | 149 |

Figures 2.3-3 to 2.3-5 show results of variogram fits. In each plot, the areal variogram fit, in four quadrants was plotted as four small windows on the left. The vertical variogram is shown as a single plot on the right. Model azimuth is plotted in the lower half.

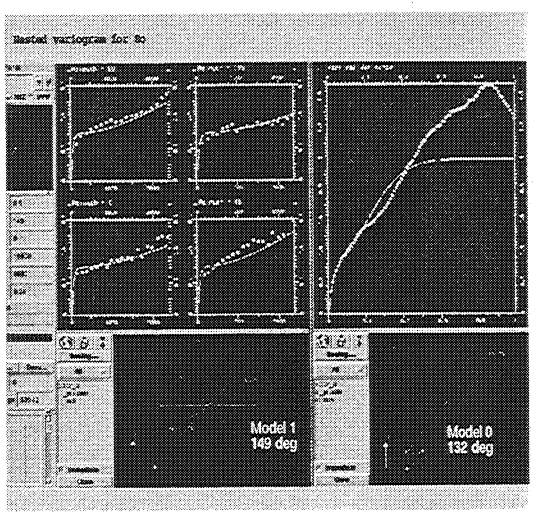



**Figure 2.3-3 Variogram fit for $S_o$.**

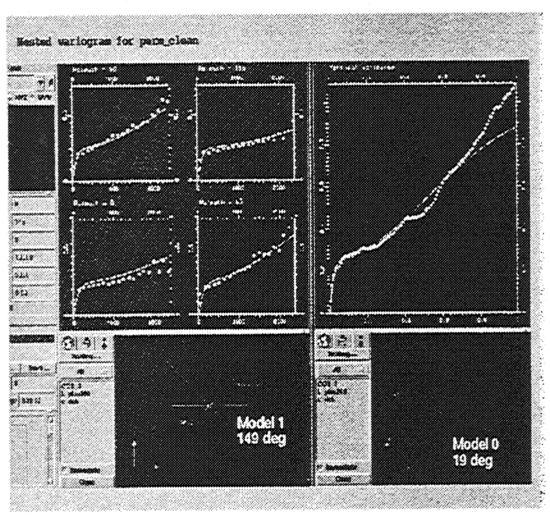



**Figure 2.3-4 Variogram fit for permeability.**

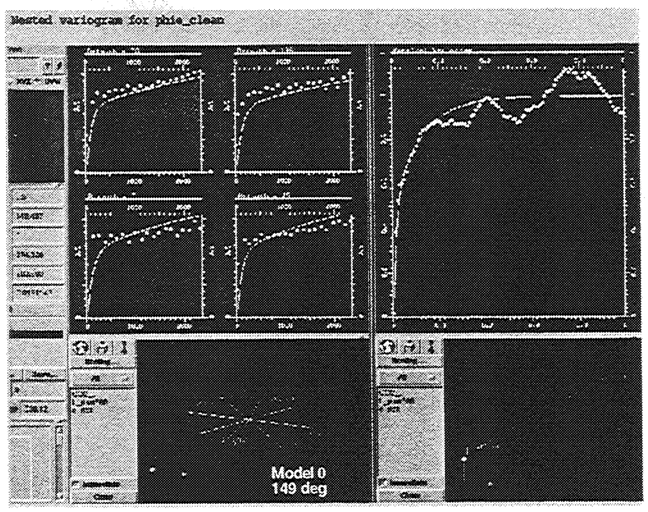


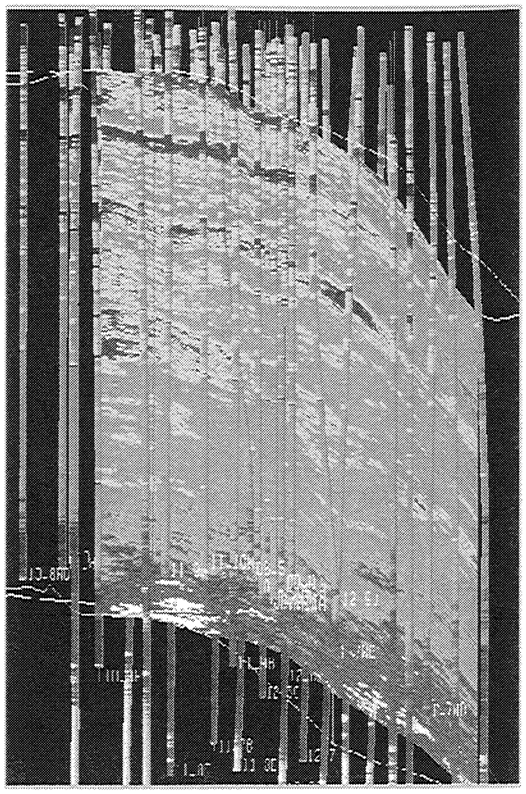

**Figure 2.3-5. Variogram fit for porosity.**

**Geostatistical Simulations:**
A few different geostatistical options were tested. Earlier models were built by separate, independent *Sequential Gaussian Simulations (SGS)* of porosity, permeability and saturations. However, the resulting cross plot (e.g., $S_o$ vs. porosity) and correlation value did not honor the input data. The $R^2$ can be either too high or too low, as shown in Table 2.4-3. A better way is to first perform a SGS on $S_o$, then perform a *Collocate Cokriging SGS (ColCok_SGS)*, using the already simulated $S_o$ as soft data. In performing the *ColCok_SGS*, we adjusted the correlation coefficient input (for porosity or ln(perm) vs. $S_o$) downwards to 0.2 – 0.3. After the *ColCoK_SGS* is done, we then compare the cross plot and $R^2$, which is close to the original input, as summarized in the right column in Table 2.4-3.

**Table 2.3-3. Different geostatistical options.**

| | **Actual Well data Wells** | **Independent SGS** | **ColCok_SGS** |
|---|---|---|---|
| **Porosity vs. $S_o$** | 0.55 | 0.66 (seed #1) | 0.56 |
| | | 0.44 (seed #2) | |
| **Ln(perm) vs. $S_o$** | 0.49 | 0.41 (seed #1) | 0.51 |
| | | 0.40 (seed #2) | |

Figure 2.3-6 shows simulated permeability (cross section) compared to well log values (cylinders). The values match quite well. Figure 2.3-7 shows the simulated porosity, permeability and oil saturation through the middle of the model. The location of the FF-Pt. and the L-Pt. surfaces are also shown.



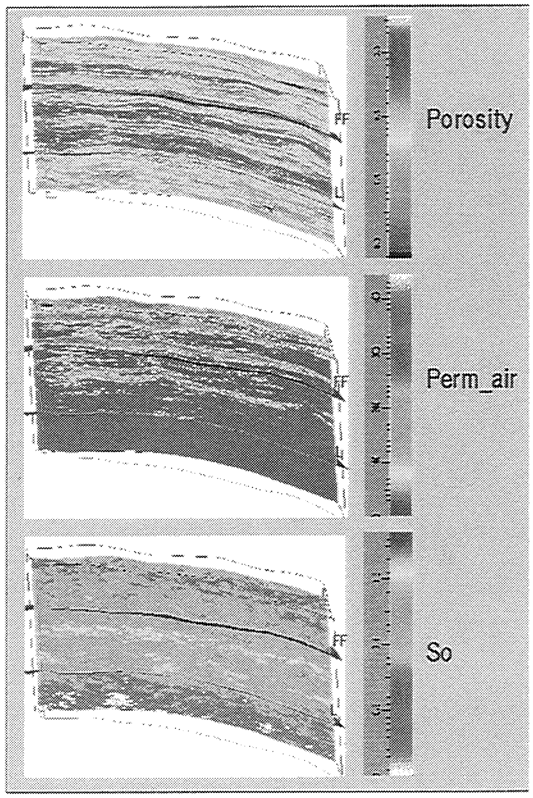



**Figure 2.3-6. Permeability cross-section.** **Figure 2.3-7. PKS cross-section.**

## 2.4 $CO_2$ PILOT FLOW SIMULATION MODEL

The earth model was scaled up for reservoir flow simulation, this was also done in G2/Gocad++. Figure 2.4-1 compares porosity cross-sections of the original earth model, and a scaled up, 36 layer reservoir flow simulation model. The degree of scale-up is mostly determined by the size of the compositional model that can be run in a reasonable amount of time.

To model hydraulic fractures, thin planes of cells were added after scale-up (see Figure 2.4-1). The flow model allows for orthogonal sets of fractures originating from the injectors. This finally results in a 60,516 grid model for Chevron's *CHEARS* simulator. The model dimension is 41 × 41 × 36. An 112,700 grid model with more vertical definition (67 layers) was also created.

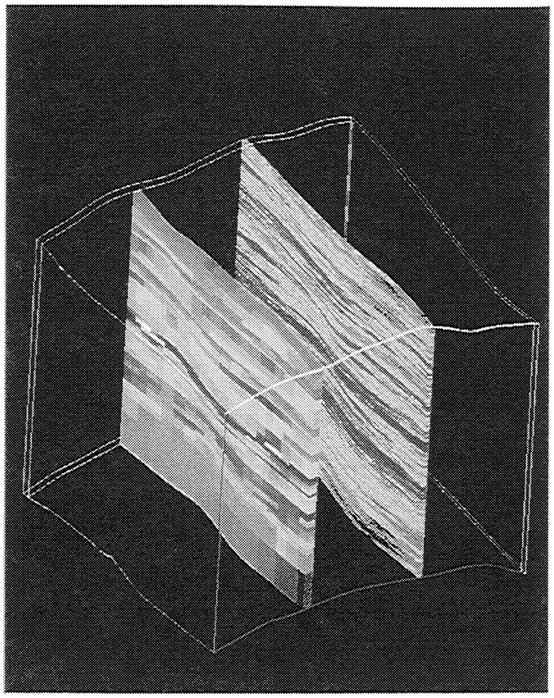


Figure 2.4-1. Compare scale-up porosity.

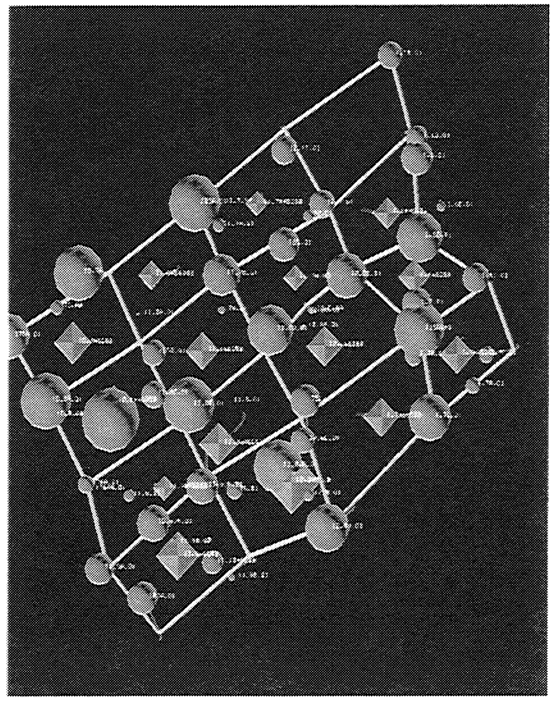


**Figure 2.4-2. Production & injection data.**

Well completion and production data were imported into G2/Gocad++, as shown in Figure 2.4-2. The spheres indicate cumulative oil production to date. The diamonds indicate cumulative water injection to date. These were then output to *CHEARS* format for history matching. PVT data from well 11-8D was also incorporated into the model. For history matching purposes, the simulation model was run in black oil mode from 1949-1999. The pressure and saturation information will then be output to a compositional version of the same model for subsequent $CO_2$ injection predictions.

Figure 2.4-3 is a plot of production and injection rates for the wells in the sixteen pattern model. Wells that started producing in the 1950's were non-fractured wells. These wells produced until the late 1980's. From 1989 to current time, new hydraulically-fractured wells were gradually put on production. The Lost Hills waterflood commenced in the early 1990's. The history match was therefore made in two stages:

(1) primary production period from 1949-1991 with no hydraulic fractures in the model .
(2) primary + waterflood period from 1991-1999, with all new wells hydraulically fractured.

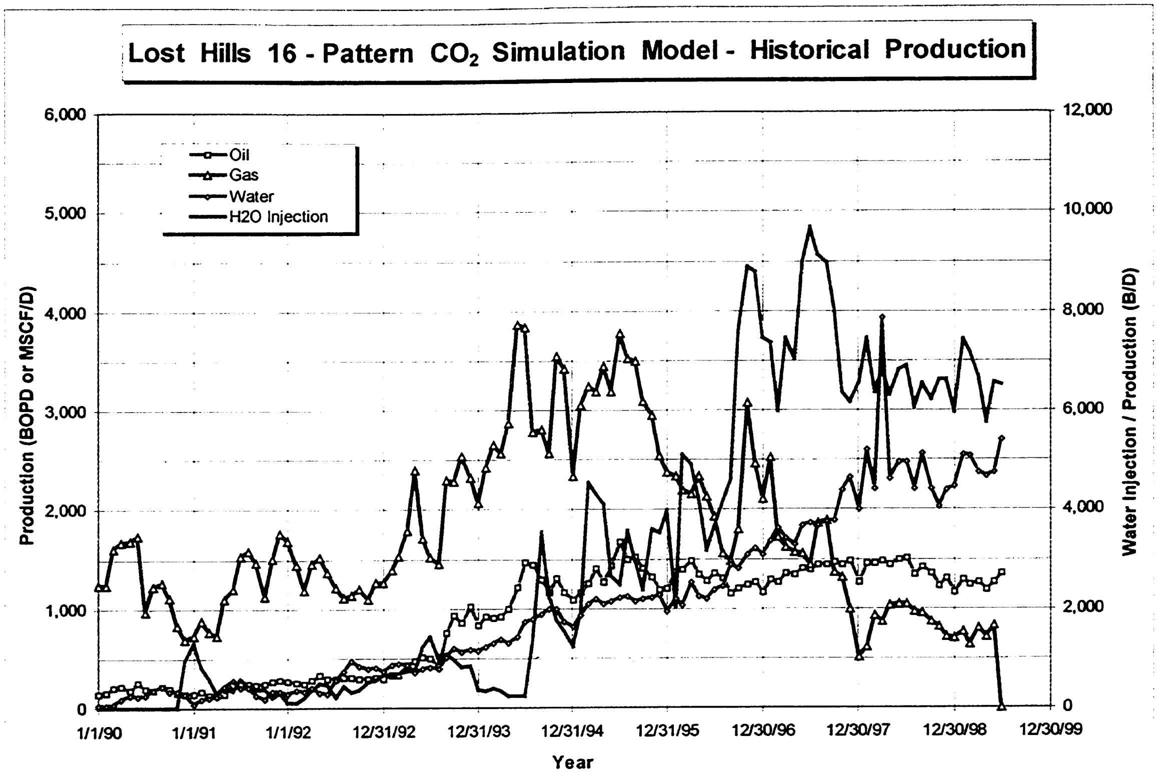



**Figure 2.4-3. Historical production and injection performance since 1990.**

**Primary ( or Pre-Frac) History Matching:**
The result of the first stage history match is satisfactory. Figures 2.4-4 and 2.4-5 show the pressure and gas saturation in model by August 1992, respectively. Localized pressure depletion can been seen, and the pressure difference from top to the bottom of model is approximately 800 psia. Free gas saturation (2-3%) existed at this time, and the observed GOR (gas-oil ratio) reached 5000 scf/stb. The history match involve the following changes in original simulation properties:

(a) increase original oil bubble point by 100 psia to 1315 psia, to better match initial GOR.
(b) reduce critical gas saturation ($S_{gc}$) from 0.02 to 0.0 to improve GOR trend match.
(c) reduce $S_{wir}$ = 0.97 * $S_{wi}$ to allow for initial water production.

Total liquid production (oil + water) *vs.* time for each well was used as input for the history matching runs.

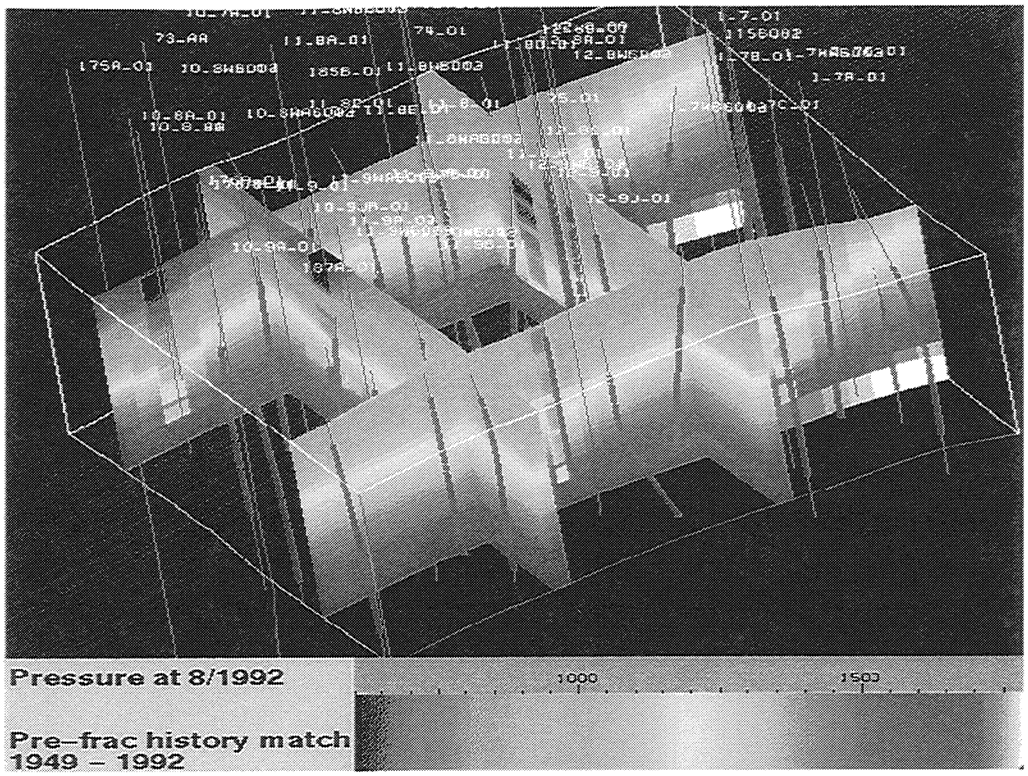



Figure 2.4-4. Pressure distribution in model - 8/92.

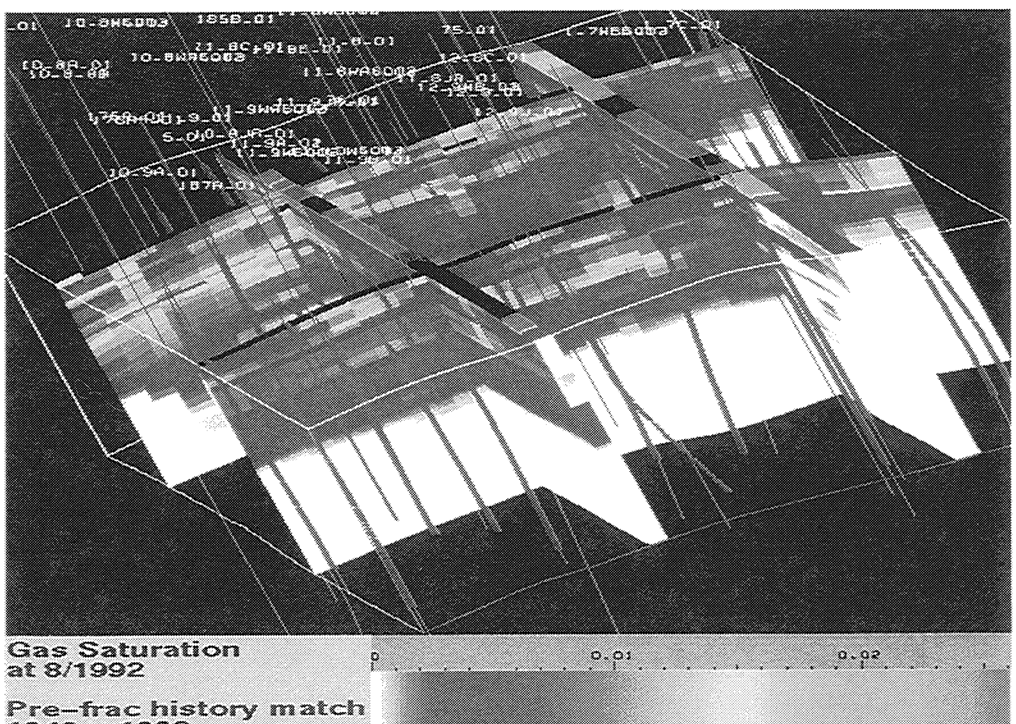



Figure 2.4-5. Gas saturation in model - 8/92.

Figures 2.4-6 through 2.4-9 are plots of production history (shown as lines) compared to simulation results (shown as squares). Figures 2.4-6 and 2.4-8 shows good match of cumulative oil and water production from 1949 - 1991. By 1992, the predicted values are lower than historical values since the model wells still have no fractures, and the low permeability of the model cannot produce the actual rates. The GOR match is good. Again, by 1992, some water injection has taken place, resulting in a decrease in GOR. Water-Oil Ratio (WOR), however, is considered only fair.

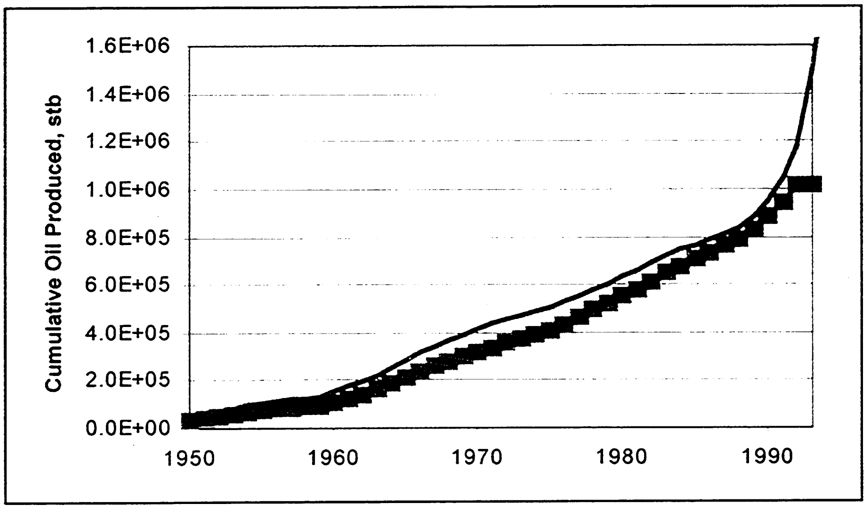



**Figure 2.4-6. Cumulative oil production match.**

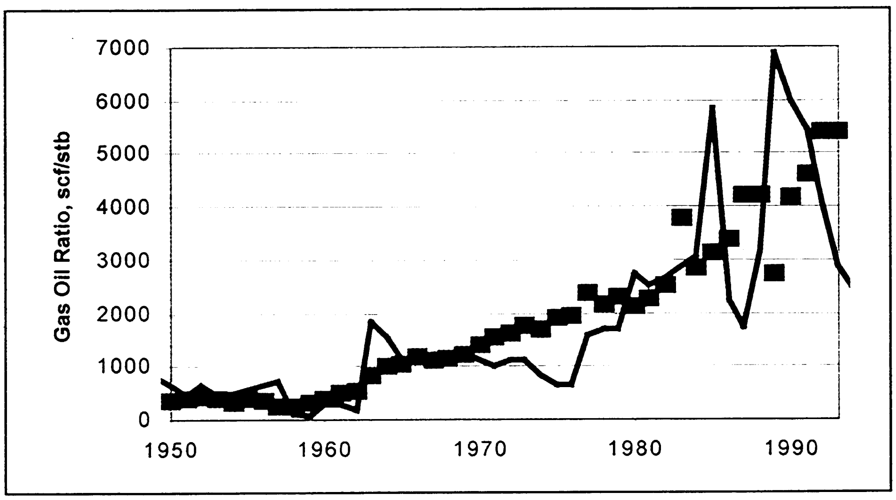



**Figure 2.4-7. Gas-Oil Ratio history match.**

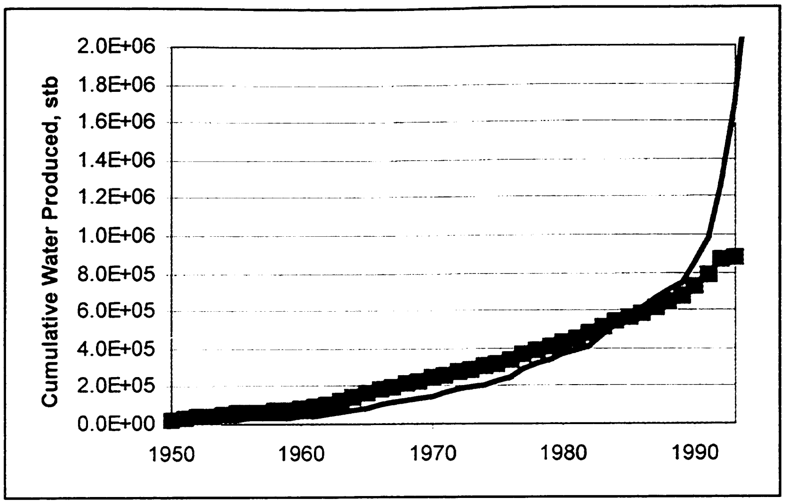



**Figure 2.4-8. Cumulative water production match.**

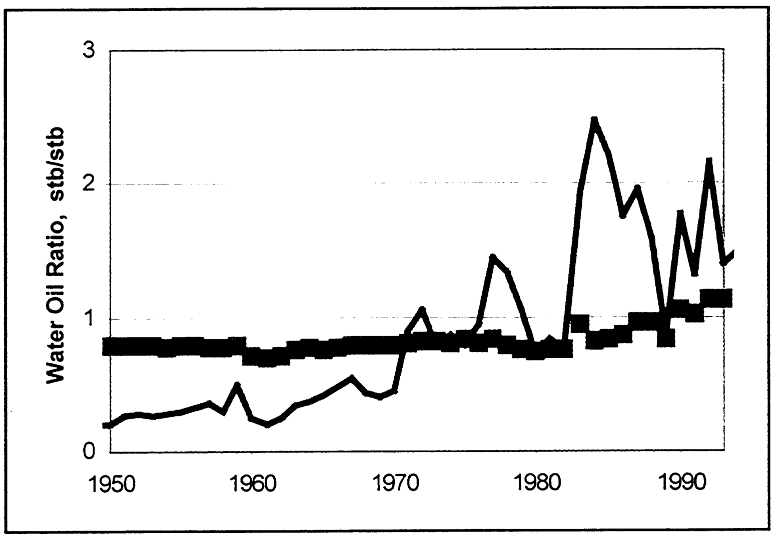



**Figure 2.4-9. Water-Oil Ratio history match.**

**Waterflooding (or Post- Frac) History Match:**

The pressure and saturations of the pre-frac model at 1992 was output to construct a model with fractures at the newer wells. We assumed in the model, all the wells put on production after 1992 are hydraulically fractured in 1992. The history match was then continued. Results are currently being analyzed and will be presented in the first quarterly report of 2000.

## 2.5 $CO_2$ PILOT DESIGN

**Objectives:**

The proposed Lost Hills $CO_2$ Pilot was designed with the following goals and objectives in mind:

- Test the technical and economic viability of $CO_2$ flooding the low permeability Diatomite resource, which is one member of California's siliceous shale reservoirs of the Monterey Formation.
- Test the technical and economic viability of $CO_2$ flooding the Diatomite resource in a timely manner (3 years or less).
- Install a configuration that enhances the chance of process success (oil response).
- Install a configuration that minimizes the likelihood of premature $CO_2$ breakthrough.
- Provide an opportunity to gather and analyze reservoir, geologic, and production data and gather facilities design information necessary to commit to a full-field project.
- Install a $CO_2$ Pilot in Lost Hills safely, without incident, and in accordance with all county, state, and federal environmental rules and regulations.

With the foregoing objectives in mind, a four pattern (2.5 acre each) $CO_2$ pilot configuration was chosen as shown in Figure 2.5-1. This configuration confines one producer (11-8D) and reduces the risk of premature breakthrough that a 5/8 acre pilot configuration would likely incur.

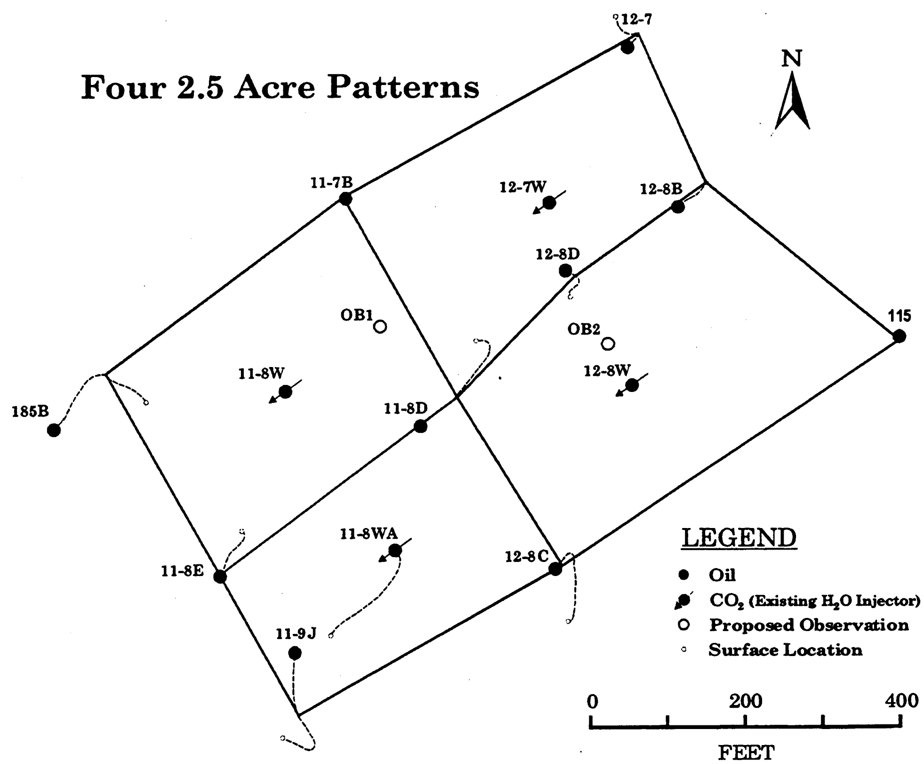



**Figure 2.5-1. Four 2.5 Acre Patterns Pilot Configuration.**

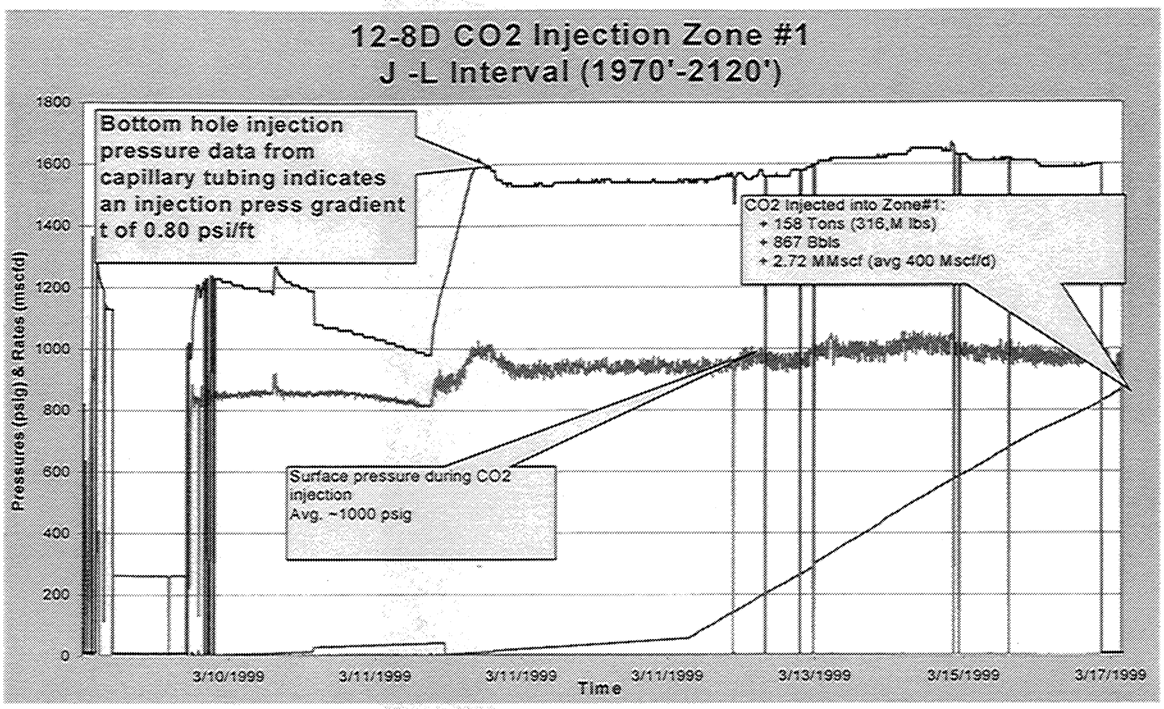



**Figure 2.6-1. Bottom hole injection pressure indicates a $CO_2$ injection gradient of 0.80 psi/ft at the top perforation.**

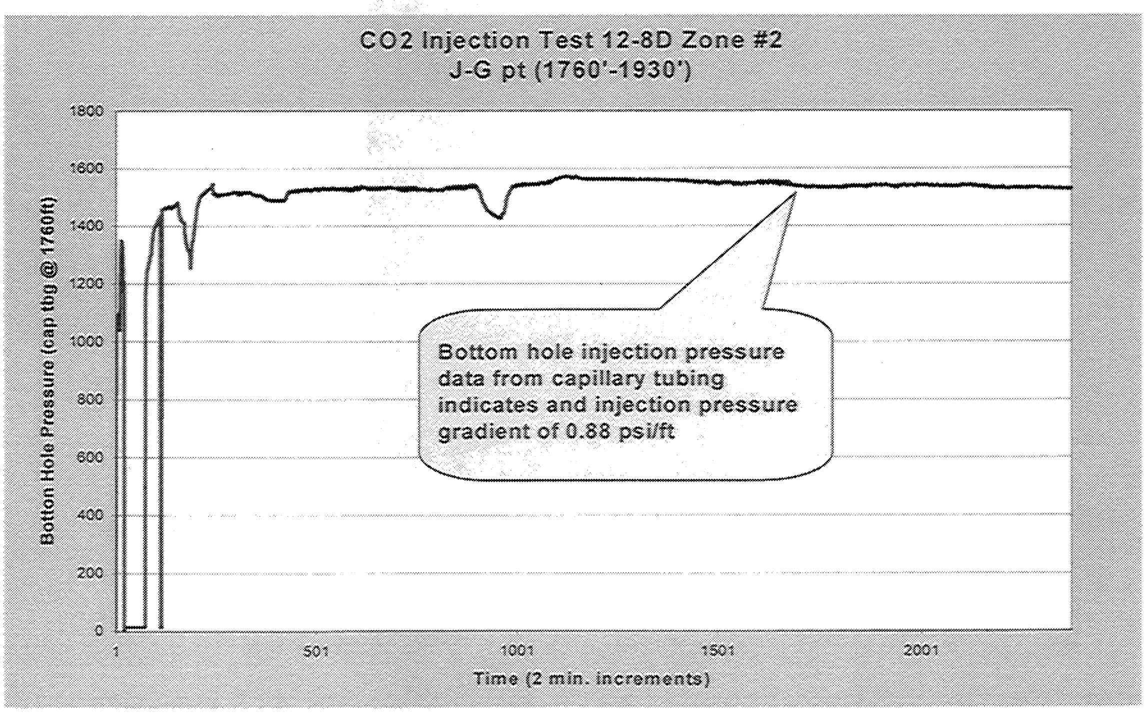



**Figure 2.6-2. Bottom hole injection pressure indicates a $CO_2$ injection pressure gradient of 0.88 psi/ft at the top perforation, above the DOG maximum limit of 0.8 psi/ft.**

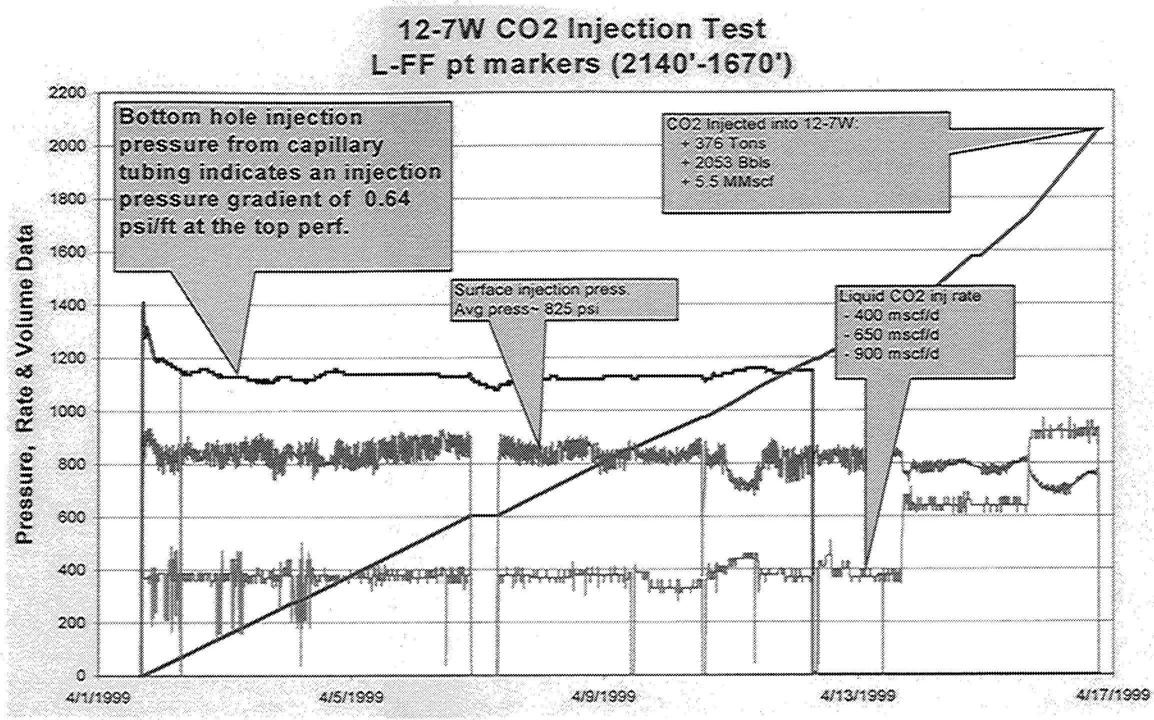



**Figure 2.6-3. Bottom hole injection pressure indicates a $CO_2$ injection gradient of 0.64 psi/ft at the top perforation, well below the DOG maximum injection gradient of 0.8 psi/ft.**

## 2.6 DRILLING AND COMPLETION

**Existing and New Producers:**
All current $CO_2$ pilot pattern production wells are currently producing. At this time no additional pattern producers will need to be drilled. All future new, or replacement producers will need to be hydraulic fracture stimulated in 4-5 stages, from the Upper Brown Shale to the D pt. Marker. Based on the corrosion monitoring program, existing tubing and sucker rods may have to be replaced with corrosion resistant materials (internally coated tubing and/or externally coated continuous sucker rods).

**Existing Injectors:**
The existing four water flood injectors (12-7W, 12-8W, 11-8W, 11-8WA) will need to be pulled to install internally coated injection packers and tubulars. During this remedial work, the wells will be reconfigured from dual injection to single string injection. The probability of success during these injector conversions is extremely low, due to subsidence related casing restrictions. As of this writing, all four injectors have known casing restrictions and/or casing damage.

**New Injectors:**
Four new $CO_2$ injection wells may have to be drilled, based on the success of the injector conversions from will be drilled. These new injection wells will receive 7" casing, two propped fracture stages (Gpt–Jpt and Jpt-Lpt). and will be completed with a single, internally coated, injection string.

**New Injector Completions:**
Injection wells will have to be propped fractured to allow injection below the specified Division of Oil and Gas (D.O.G.) permit limit of 0.8 psi/ft as measured from the top perforation of the injection interval. Bottom hole pressure data from the $CO_2$ injection test conducted on non-fractured producer 12-8D Sec 32 Fee, indicated injection pressure gradients of 0.80 psi/ft (Figure 2.6-1) for the Jpt-Lpt interval, and 0.88 psi/ft (Figure 2.6-2) for the Gpt-Lpt interval. The $CO_2$ injection pressure gradient for well 12-7W, Sec 32Fee (propped fractured water injector) was 0.64 psi/ft (Figure 2.6-3), well below the D.O.G maximum injection pressure limit of 0.8 psi/ft.

Data from the injectivity test indicates that single string injectors are adequate to achieve even $CO_2$ distribution across all injection intervals (Fpt-Lpt). Additionally, single string injectors are preferred over dual injectors from a surface rate and pressure control standpoint. Dual $CO_2$ injection wells will require twice the surface control and monitoring equipment as single string injectors. Lastly, injection tubulars and packers will have to internally coated for corrosion protection as a result of WAG (Water Alternating Gas) injection. The current injectors do not meet these requirements as none of the injection packers are internally coated and not all injectors have internally coated tubulars. Therefore the existing injectors will have to be mechanically reconfigured to accommodate $CO_2$ injection.

## 2.7 PILOT FACILITIES

**Design Basis:**
The facilities are being designed to support four 2.5 acre patterns with the following as the design basis:

- Four injection wells (existing water injectors) requiring a maximum pressure of 1200 psig. The equipment will be able to deliver a $CO_2$ rate as low as 100 mscfd per well, and as high as 500 MSCF/D per well. This range is based on the results of the recent injectivity test.
- Ten producing wells

A phased approach is being taken to establish early baseline data from the existing producing wells in the CO2 pilot.

**Phase 1 – New Gauging Facilities:**
It should be noted that the existing gauge setting can handle and monitor the production associated with the pilot. However, if the pilot is sustained it would be advantageous to install the new gauge setting to improve metering accuracy and to minimize corrosion damage to existing facilities.

The new gauging facilities will start operating in late April or early May in order to establish good baseline production data prior to starting injection. They will be designed to handle and monitor the increased $CO_2$ production associated with the $CO_2$ pilot. The key objective of these facilities will be to isolate and handle the wet gases high in $CO_2$ to prevent excessive corrosion of the existing gathering system. The time lag between phase 1 and 2 facilities will be minimal (2 to 4 months). Since these gauging facilities will have salvage value to Chevron, regardless of the outcome of the pilot, it will be proposed that the DOE only pay 25% for this portion.

Some of the existing flow lines will be utilized for the producers, while others will be replaced with cement lined piping. Funding is included in this AFE to tie additional wells into the pilot dedicated gauge setting should they also experience $CO_2$ breakthrough outside the immediate pilot patterns. The facilities will include monitoring equipment, such as density meters and online corrosion monitors, to help detect $CO_2$ breakthrough.

**Phase 2 - Injection Facilities:**
The injection equipment will be leased and consist of; storage tanks, injection pumps, heaters, monitoring equipment, and injection lines. It will be very similar to the equipment utilized for the injectivity test but with a greater capacity. SCADA equipment will be installed to enable the existing infrastructure to gather and compile the data from the pilot.

## 2.8 PILOT AND PROJECT SCHEDULE

**Pilot Schedule:**
The pilot will be constructed and operated in phases, to establish reliable baseline production data. Phase 1, which includes the new metering facility will start-up in late April or early May. Phase 2, which includes the $CO_2$ and water injection systems will start-up in late June or early July. Construction and well drilling schedules are being closely monitored to look for ways to expedite installation of the pilot.

Critical path for the start-up of the pilot is the mechanical evaluation of the injectors and subsequent re-drills if necessary. To achieve injection by the second quarter it will be necessary to schedule a drilling rig for late in the first quarter of 2000. Drlling rig schedules will be juggled to accommodate the $CO_2$ pilot schedule.

Liquid $CO_2$ supply is also a major consideration in the pilot schedule. If the pilot starts prior to June of 2000 it may be subjected to periods of low $CO_2$ supply/curtailment. After June of 2000, BOC will have additional, more dependable, supplies from Chevron's El Segundo Refinery.

A plan has been developed to institute water alternating with gas (WAG) cycles as soon as there are indications of $CO_2$ breakthrough, for any individual pattern. Control techniques learned in the early stages of the pilot will be utilized and refined throughout the pilot duration.

The pilot duration could be as short as a few months (if breakthrough cannot be controlled), or as long as 2 to 3 years if sustained success is achieved.

As soon as the major economic uncertainties of oil production and associated $CO_2$ utilization are understood, the pilot will be terminated. At that time we will finalize the feasibility evaluation of expanding to a commercial $CO_2$ injection operation.

**Commercial $CO_2$ Project Schedule:**
Based on a strategy to utilize only the $CO_2$ that is locally obtainable, additional patterns can be installed and started roughly one year after approval to proceed is obtained. This is many years sooner than if we had to wait on an interstate $CO_2$ pipeline. The first 5 MMscfd of $CO_2$ is entrained in the Lost Hills produced gas and will be the easiest to deliver to the project. Additional $CO_2$ could be delivered 6 to 12 months thereafter.

If the $CO_2$ flood goes commercial, after a successful pilot, using just the local $CO_2$ supplies, it could be on line, with 10 to 30 patterns (depends on final design injection rate), as early as 2003. Additional expansion could take place every year, for several years thereafter, until the local supply is used up, or additional supplies come to the market.

## 2.9 FACILITY ALTERNATIVES

**Pilot:**
Since the $CO_2$ supply is the most significant cost for the pilot, Decision Analysis was used to determine the best method of supplying $CO_2$. The $CO_2$ Team held a framing session to list all possible methods of $CO_2$ delivery. Since $CO_2$ is entrained in the produced gas at Lost Hills the most likely choices came down to:

1. Use liquid $CO_2$ from trucks ("Liquid Strategy") or
2. Remove $CO_2$ from the Lost Hills gas ("Amine Strategy")

The base case Net Present Value (NPV) for the liquid strategy is higher than the amine strategy. The only exception to that is if the amine plant would have significant value after termination of the pilot. Unfortunately, this is not the case since the removal of $CO_2$ from our produced gas at Lost Hills does not result in gas sales price uplift and has no measurable merit above and beyond the pilot.

The duration of the pilot must approach 3 years for an amine $CO_2$ removal plant to be economic. The preliminary design for the $CO_2$ removal plant will proceed, should it be needed to supply a long-term, commercially viable source of $CO_2$.

**Commercial $CO_2$ Project Alternatives:**
The primary economic uncertainties are; a). The amount of oil production as a result of $CO_2$ injection and b). $CO_2$ utilization per BBL of incremental oil. Therefore, the alternatives for the project will focus on the most economical supply of $CO_2$ and the best way to utilize the limited supply.

## 2.10 DOE FUNDING PLAN AND EXPENDITURES

The U.S. Department of Energy (DOE) has made funds available to explore for ways to produce mature oil fields. This program is called the Class Program. In 1996 the DOE approved a Chevron proposal for a jointly funded study of $CO_2$ enhanced oil recovery in the Buena Vista Hills siliceous shale. After two years of study, it was determined that a $CO_2$ flood was not practical at Buena Vista Hills due to low oil saturation. However, core floods and reservoir simulation showed that a $CO_2$ flood of diatomite had technical merit. A revision of the original proposal was presented and approved by the DOE to move the pilot demonstration to the Belridge Diatomite at Lost Hills. Table 2.10-1 is a summary of the original DOE funding by budget period.

**Table 2.10-1. Buena Vista Hills Field - Original DOE Funding by Budget Period.**

| | Period No. 1 | Period No. 2 | Total |
|---|---|---|---|
| **DOE** | $2,334,048 | $2,515,406 | $4,849,454 |
| **Chevron** | $2,334,049 | $2,515,406 | $4,849,455 |
| **Total** | $4,668,097 | $5,030,812 | $9,698,909 |

Table 2.10-2 is a summary of actual pilot expenditures through December 31, 1999 and Table 2.10-3 is a summary of the total remaining DOE funds. As shown in the Table 2.10-3, a little over \$2.7 MM of DOE funding is available for the Lost Hills pilot in the future.

**Table 2.10-2. Actual Pilot Expenditures Through December 31, 1999.**

| | Period No. 1 | Period No. 2 | Total |
|---|---|---|---|
| **DOE** | \$2,105,297 | \$0 | \$2,105,297 |
| **Chevron** | \$2,105,297 | \$0 | \$2,105,297 |
| **Total** | \$4,210,594 | \$0 | \$4,210,594 |

**Table 2.10-3. Lost Hills $CO_2$ Pilot – Remaining DOE Funding.**

| | Period No. 1 | Period No. 2 | Total |
|---|---|---|---|
| **DOE** | \$228,751 | \$2,515,406 | \$2,744,157 |
| **Chevron** | \$228,752 | \$2,515,406 | \$2,744,158 |
| **Total** | \$457,503 | \$5,030,812 | \$5,488,315 |

As a condition of this funding, Chevron has agreed to make all findings of the pilot demonstration public. Thus Chevron is required to write topical reports, quarterly and annual reports, and a final project report. Also Chevron is required to publish papers and give oral presentations regarding the pilot. The funding plan was revised and submitted to the DOE in agreement with the Chevron approved funding plan. The original funding spreadsheet along with the proposed revisions are included in Appendix D. Generally, we now intend to use a significant amount of the DOE funding to offset the operating expense of purchasing $CO_2$. Table 2.10-4 is the forecasted DOE expenditure forecast for the Lost Hills $CO_2$ pilot and Figure 2.10-1 is a graphical representation of the same information.

**Table 2.10-4. Year 2000 DOE Expenditure Forecast.**

| Through | This Period | Total Cumulative |
|---|---|---|
| 1999 | \$172,936 | \$2,105,297 |
| 1st Quarter - 2000 | \$283,750 | \$2,389,047 |
| 2nd Quarter – 2000 | \$853,063 | \$3,242,110 |
| 3rd Quarter - 2000 | \$565,250 | \$3,807,360 |
| 4th Quarter - 2000 | \$237,500 | \$4,044,860 |

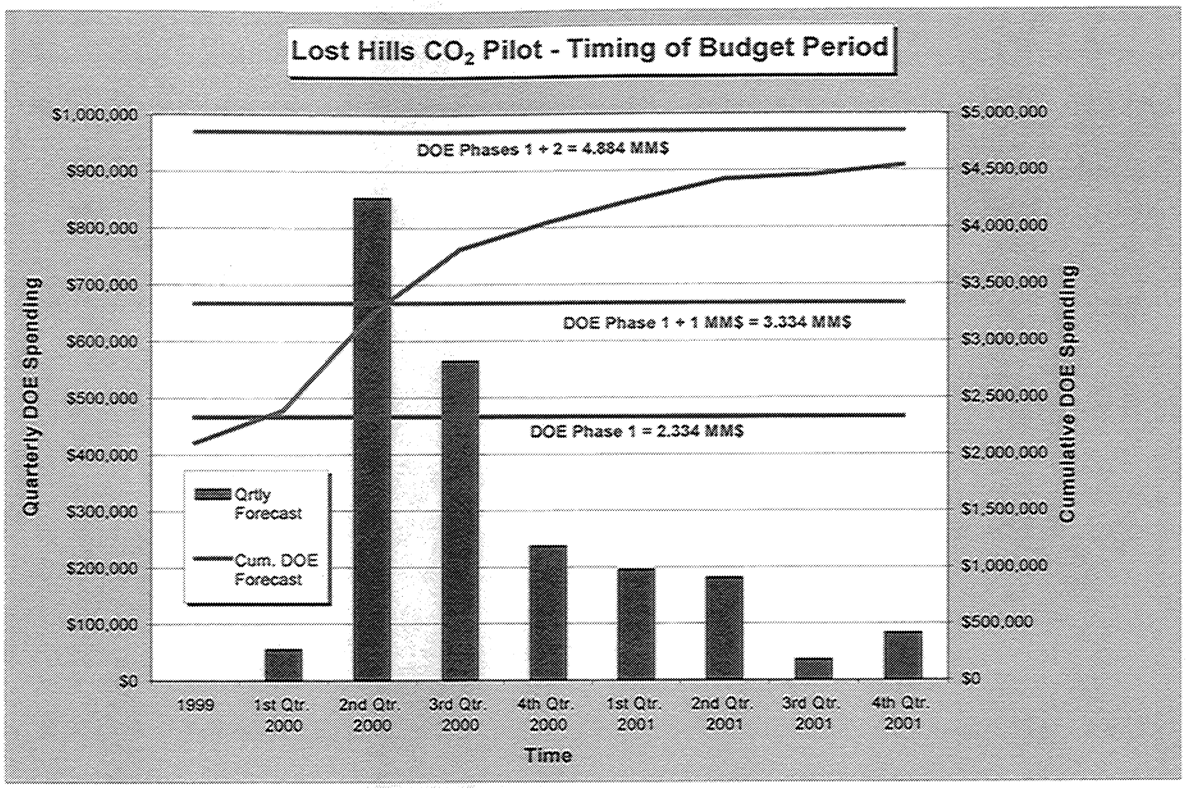



**Figure 2.10-1. Future DOE Expenditure Forecast for Lost Hills $CO_2$ Pilot.**

## 2.11 $CO_2$ SOURCES FOR LOST HILLS

**$CO_2$ Source for Pilot:**
As was discussed in "Facility Alternatives" it is more economic to supply a short lived pilot (less than 2 years in duration) with liquid $CO_2$ than by extracting it from the Lost Hills gas which contains 15% $CO_2$. As a result we have focused on getting the lowest, dependable source of liquid $CO_2$ possible. BOC Gases will be supply the CO2 and the associated storage/injection equipment for the pilot.

It is noted in the Risk Mitigation table that one of the pilot risks is that $CO_2$ will not be available for periods of up to several days. This is because the California $CO_2$ supply is limited, and will continue to be until BOC builds their $CO_2$ plant at Chevron's El Segundo refinery in the Spring/Summer of 2000. We plan to work closely with the vendor to monitor the $CO_2$ supply and to anticipate/mitigate problems.

**$CO_2$ Source for Project:**
The $CO_2$ Demand Study Group, made up of Oxy, Aera, and Chevron, was set up to determine the long-term demand for $CO_2$ in the San Joaquin Valley. The team has worked closely with companies such as Shell $CO_2$ and Ridgeway Oil to examine the feasibility of a $CO_2$ pipeline from Arizona or Colorado. Unfortunately, the cost for such a project would be between $500 million and $800 million, and require a sustained demand over 400 MMSCFD for at least 10 years. It is very unlikely that the combined demand of Aera, Oxy, and

Chevron would be that high in the foreseeable future. As a result, this project would depend on local $CO_2$ supplies and has been evaluated on that basis. The project would have limited initial growth due to the limited available supply. Some of the possible local $CO_2$ supplies are discussed below:

- **$CO_2$ from Lost Hills Produced Gas (4.5 to 6 MMSCFD):** Gas produced by Aera and Chevron in Lost Hills contains approximately 15% $CO_2$ and is processed locally at Aera's Four Star plant.
- **$CO_2$ from Cymric Casing Gas (1.5 to 2 MMSCFD):** Currently well vent gases, containing approximately 50% $CO_2$, are incinerated in steam generators in Cymric. If this $CO_2$ were removed from this casing gas it could be transported to Lost Hills via pipeline.
- **$CO_2$ from Produced Gas of Other Oil Companies (10 to 30 MMscfd in future):** Gas produced by other oil companies in the vicinity of Lost Hills is also relatively high in CO2. Facilities could be installed to remove and transport this CO2 to Lost Hills.
- **$CO_2$ from IC Engines (250 mscfd to 1 MMSCFD per engine):** Several IC engines are locate within one-half mile of the $CO_2$ flood location. Other operators have utilized $CO_2$ from the exhaust of IC engines as an injectant supply. The bugs have not been worked out of this technology yet, but may be by the time the $CO_2$ flood would go commercial.

## 2.12 FIELD OPERATING STRATEGY

**WAG Optimization:**
Based on the injectivity test performed in April, 1999 we anticipate having to deal with quick breakthrough of $CO_2$. Therefore the operating strategy for the pilot centers around the need to control breakthrough individually for each pattern, on a moments notice.

The following table depicts the planned strategy for dealing with breakthrough:

| **Injectants** | **$CO_2$ / Water Injection Rate** | **$CO_2$ Injection Duration** | **Water Injection Duration** | **WAG Cycle Times** | **Synchronize Patterns ? (i.e. same injectant at all times?)** |
|---|---|---|---|---|---|
| $CO_2$ Alt. With Water | Start with low of 100 mscfd per well and work up to 500 mscfd max. | Inject until breakthrough is detected (breakthrough defined by detection of tracer gases in one producer) | Either:<br>• Inject until desired HCPVSI is achieved or…<br>• If there is a production kick we will "ride it out" | Continue with cycles until desired cumulative HCPVSI is achieved. | Control patterns individually - some may be in $CO_2$ injection while others in water injection |

As a result of trying the above strategies, we hope to arrive at the optimal process for controlling breakthrough while monitoring for an oil kick. As noted before, the above strategies will be tested before facilities to handle high $CO_2$ are installed. We are risking shutting down injection for a while but it reduces the capital investment risked up-front. If the cumulative $CO_2$ percentage for the area of the pilot stays low enough to avoid corrosion, injection will not be stopped to wait on facilities.

**Monitoring:**
Since the pilot is located near a gauge setting most, if not all, of the process data will be transmitted to the existing data acquisition system at the main processing plant where it will be compiled for analysis at desktop workstations.

**Safety:**
The pilot will be an expanded version of the injectivity test. We intend to utilize the safety plan and the subsequent lessons learned for the pilot. The key issues were safe delivery of the $CO_2$ and keeping Chevron personnel away from high-pressure injection lines. The

revised plan calls for the access road to be re-paved for the increased traffic. In addition, more visible signs will direct $CO_2$ delivery drivers to their destination

**Manpower for Pilot:**
The equipment requiring most of the attention will be the $CO_2$ storage vessels and the injection skid. A Contractor was on-site during all injection operations for the injectivity test. This would be cost prohibitive for the pilot, therefore automatic controls will be added to monitor critical process parameters and Chevron Operations personnel will be trained on how to check and operate/adjust the equipment (particularly the pumps). Generally, priming the $CO_2$ pumps after loss of flow is the most difficult operation. Injection will be continuous unless $CO_2$ monitoring indicates it should be stopped at which time operator intervention will be required to switch to water injection

In addition, significant manpower will be required to stay up to date on all the data necessary to properly evaluate success of the pilot. Contract labor will be used to gather and analyze oil and gas samples. Analysis of the data, with the intent of making WAG decisions, will be performed by the Production Engineer, in the field. Initially, these decisions will be made by consulting with the $CO_2$ Team members but should become more routine after a while.

## 2.13 PILOT MONITORING AND SURVEILLANCE

### $CO_2$ Injection Monitoring Plan

In order to monitor the $CO_2$ pilot's performance, a comprehensive monitoring and surveillance program has been developed. Table 2.13-1 lists the types of data to be collected and its relevance.

**Table 2.13-1. Pilot Monitoring and Surveillance.**

| Source | Data Collection | | Data Evaluation & Evaluation | |
|---|---|---|---|---|
| | **Type** | **Frequency** | **Presentation** | **Derived Information** |
| Injection Wells | Tracer survey;<br>Install flow meters w/ controllers @ each injector–header;<br>Tiltmeters | Three months<br>Daily<br><br>Once | Logs; bubble plots & maps;<br><br>Map | Injection profile;<br>$CO_2$ rate, pressure & temperature<br><br>Hydraulic fracture azimuth |
| Fiberglass Cased Observation Wells | Cased hole resistivity;<br>E-M survey<br>Cross well seismic – (possible DOE funds) | Six months | Logs, charts & cross sections | Oil saturation changes<br>$CO_2$ sweep<br>$CO_2$ sweep |
| Steel Cased Observation Well | Pressure | Six months | Pressure plots | Formation pressure;<br>Needed to determine hydrocarbon pore volumes of $CO_2$ injected |
| Producing Wells | $CO_2$ concentration in produced gas;<br>Corrosion coupons; | Weekly | Rate, bubble & contour maps & plots | Performance updating; material balance; $CO_2$ response; reservoir modeling |
| Casing Collection System | Gas composition | Daily | Pressure vs. oil rate plots | Energy balance; effect on casing pressure & oil production |
| Producing Wells: Incremental Oil, Gas & Water Production | Install new AWT dedicated to pilot wells | Every two days | Bubble & contour maps & plots<br>Rate vs. Time plots<br>$HCPV_{SI}$ vs. Cum. Oil | **Baseline production vs. actual production;**<br>Incremental gas production;<br>Oil production vs. HC pore volumes injected |
| $CO_2$ Utilization | $CO_2$ injection rate vs. incremental production;<br>$CO_2$ quality % - blend in natural gas | Monthly | Injection rate vs. oil plots<br>$CO_2$ Utilization vs. Time | Meter $CO_2$ injection rate and trend vs. oil produced – long term |
| $CO_2$ Breakthrough | Detect when tracer gases arrive at producers | Daily | Gas composition plots | Online GC or frequent sampling with lab |
| Percent Recycle | Gas production composition | Monthly | Production plot<br>% $CO_2$ vs. Time Plot<br>$CO_2$ Injection & $CO_2$ Production vs. Time | Sample & trend % $CO_2$ at critical junctions of gas system – Section 3 compressor, Cahn 3 compressors, & Four Star gas plant sales point |
| Timing of Oil Response | Real time comparison of oil production vs. injection rates | Monthly | Production &. injection vs. time plots | Pilot performance |

We plan to drill 3 observation wells in April 2000. Two of these wells will be fiberglass-cased. We will run resistivity logs in these wells every six months to look for changes in oil saturation and vertical sweep. The third observation well will be steel cased and used for pressure observation.

An electro-magnetic (EM) survey is also planned for the fiberglass-cased wells. The advantage of EM is that while the resistivity logs only have a small radius of investigation around the wellbore, EM lets us see what is taking place between the wells. The two fiberglass-cased observation wells will be located on either side of a $CO_2$ injector. Thus we should be able to image $CO_2$ areal sweep in the reservoir and monitor changes over time.

If any of the existing injectors needs repalcement, then resistivity, gamma ray, neutron-density, and Electrical Micro Imaging (EMI) logs will be run. The EMI will be used to look for natural fractures.

# SECTION 3.

# TECHNOLOGY TRANSFER

## 3.1. TECHNOLOGY TRANSFER

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# APPENDIX A

# RESERVOIR FLUID STUDY

# RESERVOIR FLUID STUDY

**Introduction:**
On March 8, 1999 a liquid and gas separator sample was taken from Well 11-8D in the $CO_2$ pilot area of the Lost Hills Field. The producing interval extended from 1202' to 2560' MD and covered the entire Belridge Diatomite. The reservoir pressure ranged between 313 – 640 psig, and averaged 475 psig. Bottomhole temperature reached 120°F with an average of approximately 108°F.

The separator liquid and separator gas sample from the subject well was sent to Core Laboratories in Carrollton, Texas for use in a reservoir fluid study to examine the effects of $CO_2$ injection into the reservoir. The following test and/or analyses were conducted:

**Sample Composition:**
The composition of the separator gas was determined using gas chromatography. The composition, along with the calculated properties of the separator gas, is presented on Table A-1. The composition of separator liquid was measured through a heptanes plus residual fraction using fractional distillation. The heptanes plus fraction was further analyzed by gas chromatography through triacontanes plus. The composition and density of the separator liquid can be found on Table A-2.

**Reservoir Fluid Composition:**
The separator gas and separator liquid were physically recombined to a gas/oil ratio (GOR) of 515 scf of primary separator gas per barrel of stock tank oil. The recombination values and calculated wellstream composition based upon GOR and separator product compositions can be found on Tables A-3 and A-4. The recombined separator products equilibrated at a target bubblepoint of 950 psig at 108°F in a PVT cell. The equilibrium gas phase was physically removed and the remaining equilibrium liquid was used as the "original reservoir fluid". The measured composition of the reservoir fluid is presented on Table A-5.

**Pressure-Volume Relationship:**
A portion of the reservoir fluid was charged to a high pressure, windowed cell heated to the reported reservoir temperature of 108°F. During the constant composition expansion at this temperature, a bubblepoint was observed at 930 psig. The results of the pressure-volume relations are presented on Table A-6.

**Multi-Pressure Viscosity:**
The viscosity of the reservoir fluid was measured over a wide range of pressures at 108°F in a rolling ball viscometer. The results of the viscosity measurements are presented in Figure A-1.

**Separator (Shrinkage) Test:**
A small portion of the reservoir fluid was subjected to a single-stage separator test to determine gas/oil ratio, stock tank oil gravity and formation volume factor. These data can be found on Table A-7.

**Vapor/Liquid Equilibrium Experiment:**
A mixture of 60 mole % $CO_2$ and 40 mole % reservoir fluid was prepared in a PVT cell for use in an equilibrium (K-value) experiment at 950 psig and 108°F. The equilibrium gas phase and equilibrium liquid phase were separately analyzed for volume, density and composition. A summary of the equilibrium products can be found on Table A-8. The compositions of the two phases are presented on Tables A-9 and A-10. An additional volume of the liquid phase was prepared and subsequently charged to a rolling ball viscometer for the purpose of measuring fluid viscosity versus pressure depletion at 108°F. This $CO_2$ swollen reservoir fluid viscosity can be found in Figure A-2.

**Packed Column Displacements (Minimum Miscibility Pressure):**
A series of packed column displacements were performed at 2000, 3000, and 5000 psig at 108°F in a forty-foot, Ottawa sand packed column using the reservoir fluid and pure $CO_2$. A summary of the displacements' recoveries at 1.2 pore volumes of gas injected is presented in Figure A-3. Minimum Miscibility Pressure, or MMP, is typically defined as the pressure at which 90% oil recovery occurs after 1.2 pore volumes of $CO_2$ gas injected. Analysis of Figure A-3 shows that this occurs at 5000 psig for the Lost Hills reservoir fluid.

**Asphaltene Flocculation Experiments:**
A 25 cc sample of reservoir fluid was placed in a high pressure PVT cell at an overburden pressure of 950 psig and reservoir temperature of 108°F. After reaching equilibrium, the sample was scanned using near-infrared (NIR) spectrophotometer to establish an absolute transmittance level for reference. Once the reference was established, the fluid was slowly mixed and maintained at 950 psig as pure $CO_2$ was added to the system. During $CO_2$ additions, scans in a near-infrared range of wavelengths from 1500 to 1700 nm were repeated at every cc increment of gas addition from 0 to 60cc (0 mole % to 207 mole % $CO_2$ added to reservoir fluid, respectively). Results of these NIR scans at reservoir temperature are presented in graphical form on Figure A-4. Following the gas addition, the system was equilibrated at 950 psig and 108°F and an additional reference scan performed. While mixing the cell contents, the system was slowly pressurized from 950 psig to 5100 psig. During this pressurization process, scans were performed at every 50-psig pressure increment. These data are also presented graphically in Figure A-4. Neither during the process of titrating the reservoir fluid with $CO_2$ nor subsequent pressurization of the system was an asphaltene onset observed.

**Summary:**
The results of the reservoir fluid study are encouraging for the proposed Lost Hills $CO_2$ pilot. Although the packed column displacement tests resulted in a Minimum Miscibility Pressure (MMP) of 5000 psig, there is still a significant benefit from $CO_2$ injection. Figure A-5 shows a comparison of the original reservoir fluid viscosity to the $CO_2$ swollen fluid viscosity as a function of pressure. Although the Lost Hills $CO_2$ flood will be operating well below MMP

and in the 500 – 1100 psig range, a fluid viscosity reduction in excess of 50% can still be achieved.

In addition, many $CO_2$ projects in West Texas and Colorado have been hampered with a severe asphaltene precipitation problem subsequent to commencing $CO_2$ injection. Analyses of the asphaltene flocculation experiments indicate that this will not be a problem with Lost Hills oil.

## Chevron U.S.A. Production Company

**Well 11-8D 32 Fee**

RFL 990039

## COMPOSITION OF PRIMARY STAGE SEPARATOR GAS

(by Programmed-Temperature, Capillary Chromatography)

| Component | Mol % | Plant Products (GPM) | Liquid Density (gm/cc) | MW |
|---|---|---|---|---|
| Hydrogen Sulfide | 0.00 | | | |
| Carbon Dioxide | 26.70 | | 0.8172 | 44.010 |
| Nitrogen | 0.02 | | 0.8086 | 28.013 |
| Methane | 64.26 | | 0.2997 | 16.043 |
| Ethane | 5.48 | 1.464 | 0.3562 | 30.070 |
| Propane | 0.71 | 0.195 | 0.5070 | 44.097 |
| iso-Butane | 0.92 | 0.301 | 0.5629 | 58.123 |
| n-Butane | 0.45 | 0.142 | 0.5840 | 58.123 |
| iso-Pentane | 0.46 | 0.168 | 0.6244 | 72.150 |
| n-Pentane | 0.21 | 0.076 | 0.6311 | 72.150 |
| Hexanes | 0.27 | 0.105 | 0.6850 | 84.0 |
| Heptanes | 0.35 | 0.147 | 0.7220 | 96.0 |
| Octanes | 0.12 | 0.055 | 0.7450 | 107 |
| Nonanes | 0.04 | 0.020 | 0.7640 | 121 |
| Decanes | 0.01 | 0.005 | 0.7780 | 134 |
| **Totals ..........** | 100.00 | 2.678 | | |

### SAMPLING CONDITIONS

**48 psig**
**72 °F**

Gas Cylinder
DEN9009

**Average Sample Properties**

Critical Pressure, psia .......................... 771.4
Critical Temperature, °R ........................ 424.8

Average Molecular Weight .................... 26.06
Calculated Gas Gravity ( air = 1.000 ) .. 0.900

**at 14.73 psia and 60 °F**

Heating Value, Btu/scf dry gas*
Gross ................................................ 877

**Properties of Plus Fractions**

| Component | Mol % | Liquid Density (gm/cc) | Liquid API Gravity | MW |
|---|---|---|---|---|
| Heptanes plus | 0.52 | 0.7326 | 61.5 | 101.2 |

Note: Component properties assigned from literature.
* ref: Gas Producers & Suppliers Association (GPSA) Engineering Data Book

**Table A-1. Composition of Primary Stage Separator Gas.**

## Chevron U.S.A. Production Company

**Well 11-8D 32 Fee**

RFL 990039

## COMPOSITION OF PRIMARY STAGE SEPARATOR LIQUID

(by Low Temperature Distillation / Programmed-Temperature, Capillary Chromatography)

| Component | Mol % | Wt % | Liquid Density (gm/cc) | MW |
|---|---|---|---|---|
| Hydrogen Sulfide | 0.00 | 0.00 | | |
| Carbon Dioxide | 0.49 | 0.08 | 0.8172 | 44.010 |
| Nitrogen | 0.00 | 0.00 | | |
| Methane | 0.28 | 0.02 | 0.2997 | 16.043 |
| Ethane | 0.24 | 0.03 | 0.3562 | 30.070 |
| Propane | 0.11 | 0.02 | 0.5070 | 44.097 |
| iso-Butane | 0.25 | 0.05 | 0.5629 | 58.123 |
| n-Butane | 0.18 | 0.04 | 0.5840 | 58.123 |
| iso-Pentane | 0.53 | 0.14 | 0.6244 | 72.150 |
| n-Pentane | 0.42 | 0.11 | 0.6311 | 72.150 |
| Hexanes | 2.42 | 0.75 | 0.6850 | 84.0 |
| Heptanes | 7.50 | 2.67 | 0.7220 | 96.0 |
| Octanes | 9.91 | 3.93 | 0.7450 | 107 |
| Nonanes | 7.98 | 3.58 | 0.7640 | 121 |
| Decanes | 7.00 | 3.48 | 0.7780 | 134 |
| Undecanes | 5.44 | 2.97 | 0.7890 | 147 |
| Dodecanes | 4.81 | 2.87 | 0.8000 | 161 |
| Tridecanes | 4.48 | 2.91 | 0.8110 | 175 |
| Tetradecanes | 3.59 | 2.53 | 0.8220 | 190 |
| Pentadecanes | 3.16 | 2.41 | 0.8320 | 206 |
| Hexadecanes | 2.75 | 2.26 | 0.8390 | 222 |
| Heptadecanes | 2.59 | 2.28 | 0.8470 | 237 |
| Octadecanes | 2.74 | 2.55 | 0.8520 | 251 |
| Nonadecanes | 2.19 | 2.14 | 0.8570 | 263 |
| Eicosanes | 2.58 | 2.63 | 0.8620 | 275 |
| Heneicosanes | 1.86 | 2.01 | 0.8670 | 291 |
| Docosanes | 1.83 | 2.07 | 0.8720 | 305 |
| Tricosanes | 1.63 | 1.92 | 0.8770 | 318 |
| Tetracosanes | 1.69 | 2.07 | 0.8810 | 331 |
| Pentacosanes | 1.16 | 1.48 | 0.8850 | 345 |
| Hexacosanes | 1.09 | 1.45 | 0.8890 | 359 |
| Heptacosanes | 1.30 | 1.80 | 0.8930 | 374 |
| Octacosanes | 0.93 | 1.34 | 0.8960 | 388 |
| Nonacosanes | 1.29 | 1.92 | 0.8990 | 402 |
| Triacontanes plus | 15.58 | 43.49 | 1.1127 | 753 |
| **Totals ..........** | 100.00 | 100.00 | | |

### SAMPLING CONDITIONS

**48 psig**
**72 °F**

Liquid Cylinder
226387D

**Average Sample Properties**

Average Molecular Weight .................... 269.69
Calculated Density at 0 psig and 60 °F . 0.9245

**Properties of Plus Fractions**

| Plus Fraction | Mol% | Wt% | Liquid Density (gm/cc) | Liquid API Gravity | MW |
|---|---|---|---|---|---|
| Heptanes plus | 95.08 | 98.76 | 0.9296 | 20.6 | 280 |
| Undecanes plus | 62.69 | 85.10 | 0.9659 | 14.9 | 366 |
| Pentadecanes plu: | 44.37 | 73.82 | 0.9963 | 10.4 | 449 |
| Eicosanes plus | 30.94 | 62.18 | 1.0308 | 5.6 | 542 |
| Pentacosanes plu: | 21.35 | 51.48 | 1.0717 | 0.4 | 650 |
| Triacontanes plus | 15.58 | 43.49 | 1.1127 | -4.5 | 753 |

**Table A-2. Composition of Primary Stage Separator Liquid.**

## Chevron U.S.A. Production Company

**Well 11-8D 32 Fee**

RFL 990039

## WELLSTREAM RECOMBINATION CALCULATION

(based on field production data)

### Conditions for Recombination Calculations

Primary Stage at 48 psig and 72 °F

***Field Gas Rate Correction Factors -***

| | |
|---|---|
| Gas Gravity (air=1.000) | ** |
| Gas Gravity Factor, Fg | ** |
| Gas Deviation Factor, Z | ** |
| Super Compressibility Factor, Fpv | ** |
| Pressure Base, psia | 14.730 |

***Laboratory Gas Rate Correction Factors -***

| | |
|---|---|
| Gas Gravity (air=1.000) | 0.900 |
| Gas Gravity Factor, Fg (not applied) | 1.0542 |
| Gas Deviation Factor*, Z | 0.990 |
| Supercompressibility Factor, Fpv (not applied) | 1.0052 |
| Pressure Base, psia | 14.730 |

***Laboratory Liquid Rate Correction Factors -***

| | |
|---|---|
| Liquid Volume Factor, S°bbl/bbl @ 60 °F | na |
| Bitumen, Sediment & Water (BS&W) Factor | 1.000 |

***Field Measured Rates and Ratios -***

| | |
|---|---|
| Primary Stage Gas Flow Rate, Mscf/D | 34.00 |
| Primary Stage Liquid Flow Rate, bbl/D | 66.00 |
| Primary Stage Gas / Oil Ratio, scf/S°bbl | 515.15 |

***Recombination Rates and Ratios -***

| | |
|---|---|
| Primary Stage Gas Flow Rate, Mscf/D | 34.00 |
| Primary Stage Liquid Flow Rate, bbl/D | 66.00 |
| Primary Stage Gas / Oil Ratio, scf/bbl | 515.15 |

***Wellstream Recombination Ratio mol/mol*** .......... **1.1377**

* From: Standing, M.B., "Volumetric and Phase Behavior of Oil Field Hydrocarbon Systems", SPE (Dallas),1977, 8th Edition, Appendix II.

** Data not supplied to Core Laboratories

**Table A-3. Wellstream Recombination Calculation.**

## Chevron U.S.A. Production Company
**Well 11-8D 32 Fee**
RFL 990039

## CALCULATED COMPOSITION OF WELLSTREAM
(from calculated recombination of separator products)

| Component | Mol % | Wt% | Liquid Density (gm/cc) | MW |
|---|---|---|---|---|
| Hydrogen Sulfide | 0.00 | 0.00 | | |
| Carbon Dioxide | 14.44 | 4.54 | 0.8172 | 44.010 |
| Nitrogen | 0.01 | 0.00 | 0.8086 | 28.013 |
| Methane | 34.33 | 3.93 | 0.2997 | 16.043 |
| Ethane | 3.03 | 0.65 | 0.3562 | 30.070 |
| Propane | 0.43 | 0.14 | 0.5070 | 44.097 |
| iso-Butane | 0.61 | 0.25 | 0.5629 | 58.123 |
| n-Butane | 0.32 | 0.13 | 0.5840 | 58.123 |
| iso-Pentane | 0.49 | 0.25 | 0.6244 | 72.150 |
| n-Pentane | 0.31 | 0.16 | 0.6311 | 72.150 |
| Hexanes | 1.28 | 0.77 | 0.6850 | 84.0 |
| Heptanes | 3.69 | 2.53 | 0.7220 | 96.0 |
| Octanes | 4.70 | 3.59 | 0.7450 | 107 |
| Nonanes | 3.75 | 3.24 | 0.7640 | 121 |
| Decanes | 3.28 | 3.14 | 0.7780 | 134 |
| Undecanes | 2.54 | 2.67 | 0.7890 | 147 |
| Dodecanes | 2.25 | 2.59 | 0.8000 | 161 |
| Tridecanes | 2.10 | 2.62 | 0.8110 | 175 |
| Tetradecanes | 1.68 | 2.28 | 0.8220 | 190 |
| Pentadecanes | 1.48 | 2.18 | 0.8320 | 206 |
| Hexadecanes | 1.29 | 2.04 | 0.8390 | 222 |
| Heptadecanes | 1.21 | 2.05 | 0.8470 | 237 |
| Octadecanes | 1.28 | 2.29 | 0.8520 | 251 |
| Nonadecanes | 1.02 | 1.92 | 0.8570 | 263 |
| Eicosanes | 1.21 | 2.38 | 0.8620 | 275 |
| Heneicosanes | 0.87 | 1.81 | 0.8670 | 291 |
| Docosanes | 0.86 | 1.87 | 0.8720 | 305 |
| Tricosanes | 0.76 | 1.73 | 0.8770 | 318 |
| Tetracosanes | 0.79 | 1.87 | 0.8810 | 331 |
| Pentacosanes | 0.54 | 1.33 | 0.8850 | 345 |
| Hexacosanes | 0.51 | 1.31 | 0.8890 | 359 |
| Heptacosanes | 0.61 | 1.63 | 0.8930 | 374 |
| Octacosanes | 0.44 | 1.22 | 0.8960 | 388 |
| Nonacosanes | 0.60 | 1.72 | 0.8990 | 402 |
| Triacontanes plus | 7.29 | 39.17 | 1.1127 | 753 |
| **Totals ...........** | 100.00 | 100.00 | | |

### RECOMBINATION CONDITIONS

**48 psig**
**72 °F**

#### Recombination Parameters

Primary Stage Gas / Oil Ratio, scf/bbl
at recombination conditions ................ 515.15
Wellstream Recombination Ratio
moles gas / mole liquid ........................ 1.1377

#### Average Wellstream Properties

Average Molecular Weight .................... 140.0
Calculated Density at 0 psig and 60 °F . 0.8388

#### Properties of Plus Fractions

| Plus Fraction | Mol% | Wt% | Liquid Density (gm/cc) | Liquid API Gravity | MW |
|---|---|---|---|---|---|
| Heptanes plus | 44.75 | 89.18 | 0.9291 | 20.7 | 279 |
| Undecanes plus | 29.33 | 76.68 | 0.9659 | 14.9 | 366 |
| Pentadecanes plu: | 20.76 | 66.52 | 0.9963 | 10.4 | 449 |
| Eicosanes plus | 14.48 | 56.04 | 1.0308 | 5.6 | 542 |
| Pentacosanes plu: | 9.99 | 46.38 | 1.0717 | 0.4 | 650 |
| Triacontanes plus | 7.29 | 39.17 | 1.1127 | -4.5 | 753 |

**Table A-4. Calculated Composition of Wellstream.**

## Chevron U.S.A. Production Company

**Well 11-8D 32 Fee**

RFL 990039

### COMPOSITION OF Pb ADJUSTED RESERVOIR FLUID*

(by Flash, Extended-Capillary Chromatography)

| Component Name | Mol % | Wt % | Liquid Density (gm/cc) | MW |
|---|---|---|---|---|
| Hydrogen Sulfide | 0.00 | 0.00 | 0.8006 | 34.08 |
| Carbon Dioxide | 11.07 | 2.54 | 0.8172 | 44.01 |
| Nitrogen | 0.00 | 0.00 | 0.8086 | 28.013 |
| Methane | 16.17 | 1.35 | 0.2997 | 16.043 |
| Ethane | 3.21 | 0.50 | 0.3562 | 30.07 |
| Propane | 0.71 | 0.16 | 0.5070 | 44.097 |
| iso-Butane | 0.96 | 0.29 | 0.5629 | 58.123 |
| n-Butane | 0.56 | 0.17 | 0.5840 | 58.123 |
| iso-Pentane | 0.78 | 0.29 | 0.6244 | 72.15 |
| n-Pentane | 0.48 | 0.18 | 0.6311 | 72.15 |
| Hexanes | 1.59 | 0.70 | 0.6850 | 84 |
| Heptanes | 5.80 | 2.90 | 0.7220 | 96 |
| Octanes | 6.60 | 3.68 | 0.7450 | 107 |
| Nonanes | 5.07 | 3.19 | 0.7640 | 121 |
| Decanes | 4.53 | 3.16 | 0.7780 | 134 |
| Undecanes | 3.46 | 2.65 | 0.7890 | 147 |
| Dodecanes | 3.35 | 2.81 | 0.8000 | 161 |
| Tridecanes | 3.19 | 2.91 | 0.8110 | 175 |
| Tetradecanes | 2.58 | 2.55 | 0.8220 | 190 |
| Pentadecanes | 2.28 | 2.45 | 0.8320 | 206 |
| Hexadecanes | 1.90 | 2.20 | 0.8390 | 222 |
| Heptadecanes | 1.83 | 2.26 | 0.8470 | 237 |
| Octadecanes | 1.68 | 2.20 | 0.8520 | 251 |
| Nonadecanes | 1.48 | 2.03 | 0.8570 | 263 |
| Eicosanes | 1.47 | 2.10 | 0.8620 | 275 |
| Heneicosanes | 1.22 | 1.84 | 0.8670 | 291 |
| Docosanes | 1.21 | 1.92 | 0.8720 | 305 |
| Tricosanes | 0.97 | 1.60 | 0.8770 | 318 |
| Tetracosanes | 0.96 | 1.65 | 0.8810 | 331 |
| Pentacosanes | 0.85 | 1.52 | 0.8850 | 345 |
| Hexacosanes | 0.90 | 1.68 | 0.8890 | 359 |
| Heptacosanes | 0.82 | 1.60 | 0.8930 | 374 |
| Octacosanes | 0.79 | 1.59 | 0.8960 | 388 |
| Nonacosanes | 0.89 | 1.86 | 0.8990 | 402 |
| Triacontanes plus | 10.64 | 41.47 | 1.1074 | 748 |
| Totals | 100.00 | 100.00 | | |

*** Bubblepoint Adjusted to**

**930 psig at 108°F**

**Total Sample Properties**

Molecular Weight ...................................... 192.04

Equivalent Liquid Density, gm/scc ............ 0.8849

| Plus Fractions | Mol % | Wt % | Density | MW |
|---|---|---|---|---|
| Heptanes plus | 64.47 | 93.82 | 0.9281 | 279 |
| Undecanes plus | 42.47 | 80.89 | 0.9641 | 366 |
| Pentadecanes plus | 29.89 | 69.97 | 0.9948 | 450 |
| Eicosanes plus | 20.72 | 58.83 | 1.0293 | 545 |
| Pentacosanes plus | 14.89 | 49.72 | 1.0648 | 641 |
| Triacontanes plus | 10.64 | 41.47 | 1.1074 | 748 |

**Table A-5. Composition of $P_b$ Adjusted Reservoir Fluid.**

## Chevron U.S.A. Production Company

**Well 11-8D 32 Fee**

RFL 990039

**VOLUMETRIC DATA**

(at 108 °F)

Saturation Pressure (Psat) ................................ 930 psig
Density at Psat ...................................................... 0.8811 gm/cc
Thermal Exp @ 5000 psig ................................. 1.01954 V at 108 °F / V at 60 °F

**AVERAGE SINGLE-PHASE COMPRESSIBILITIES**

| Pressure Range psig | | | Single-Phase Compressibility v/v/psi |
|---|---|---|---|
| 5000 | to | 4500 | 4.64 E -6 |
| 4500 | to | 4000 | 4.73 E -6 |
| 4000 | to | 3500 | 4.84 E -6 |
| 3500 | to | 3000 | 4.96 E -6 |
| 3000 | to | 2500 | 5.11 E -6 |
| 2500 | to | 2000 | 5.30 E -6 |
| 2000 | to | 1500 | 5.56 E -6 |
| 1500 | to | 1000 | 5.92 E -6 |
| 1000 | to | 930 | 6.20 E -6 |

## PRESSURE-VOLUME RELATIONS

(at 108 °F)

| Pressure psig | Relative Volume (A) | Y-Function (B) | Density gm/cc |
|---|---|---|---|
| 5000 | 0.9793 | | 0.8997 |
| 4500 | 0.9816 | | 0.8977 |
| 4000 | 0.9839 | | 0.8955 |
| 3500 | 0.9863 | | 0.8934 |
| 3000 | 0.9887 | | 0.8912 |
| 2500 | 0.9912 | | 0.8889 |
| 2000 | 0.9939 | | 0.8865 |
| 1500 | 0.9966 | | 0.8841 |
| 1400 | 0.9972 | | 0.8836 |
| 1300 | 0.9978 | | 0.8831 |
| 1200 | 0.9984 | | 0.8825 |
| 1100 | 0.9990 | | 0.8820 |
| 1000 | 0.9996 | | 0.8815 |
| b»930 | 1.0000 | | 0.8811 |
| 929 | 1.0009 | 1.187 | |
| 928 | 1.0019 | 1.105 | |
| 927 | 1.0031 | 1.023 | |

(A) Relative Volume: V/Vsat or volume at indicated pressure per volume at saturation pressure.

(B) Where: $Y = \dfrac{(Psat - P)}{(Pabs) * (V/Vsat - 1)}$

**Table A-6. Pressure Volume Relations.**

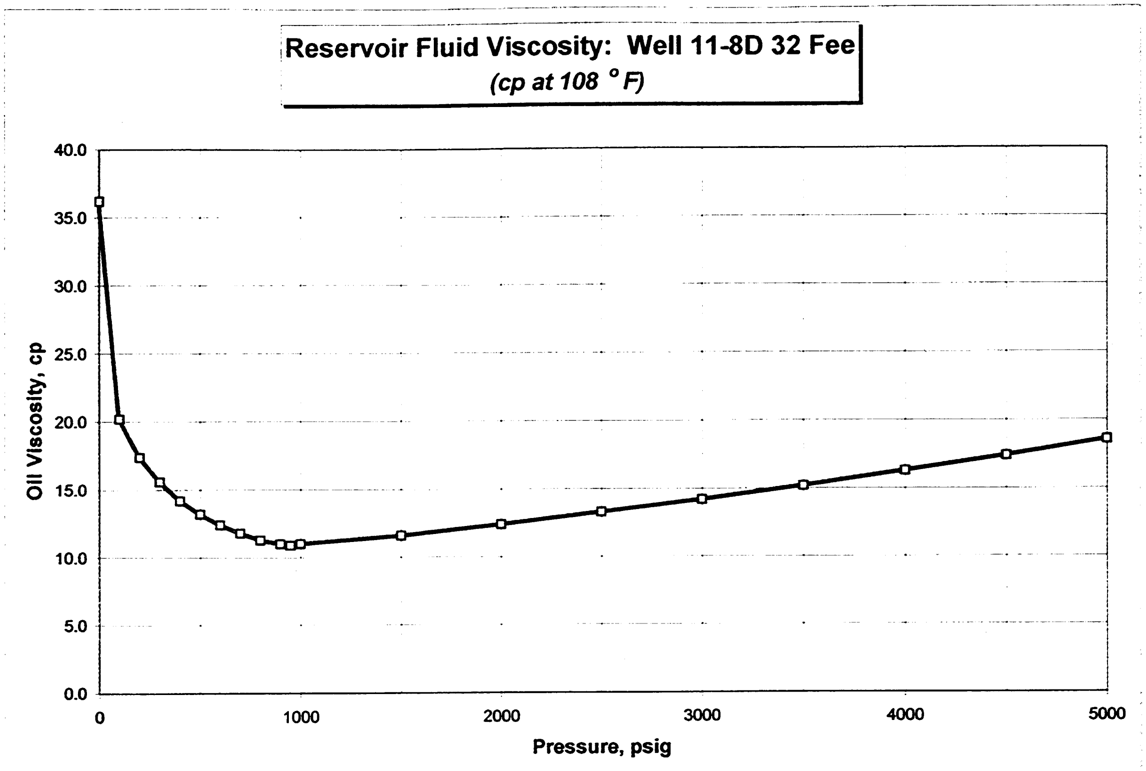



**Figure A-1. Reservoir Fluid Viscosity from Well 11-8D.**

Chevron U.S.A. Production Company
**Well 11-8D 32 Fee**
RFL 990039

RESERVOIR FLUID SHRINKAGE ANALYSIS

| Flash Conditions psig | Flash Conditions °F | Gas/Oil Ratio ( scf/bbl ) (A) | Gas/Oil Ratio ( scf/STbbl ) (B) | Stock Tank Oil Gravity at 60 °F ( °API ) | Liquid Shrinkage Factor (C) | Specific Gravity of Flashed Gas ( Air=1.000 ) | Oil Phase Density ( gm/cc ) |
|---|---|---|---|---|---|---|---|
| 930 | 108 | | | | | | 0.8811 |
| 0 | 68 | 214 | 214 | 21.7 | .9064 | 1.056 | 0.9197 |
| | | | Rsfb = 214 | | | | |

(A) Cubic Feet of gas at 14.73 psia and 60 °F per barrel of oil at indicated pressure and temperature.
(B) Cubic Feet of gas at 14.73 psia and 60 °F per barrel of stock tank oil at 60 °F.
(C) Barrels of stock tank oil at 60 °F per barrel of oil at indicated pressure and temperature.

**Table A-7. Reservoir Fluid Shrinkage Analysis.**

## Chevron U.S.A. Production Company

**Well 11-8D 32 Fee**

RFL 990039

## INJECTION GAS / RESERVOIR FLUID EQUILIBRIUM

**(Carbon Dioxide Added to Reservoir Fluid)**

(at 108 °F)

60 mole % Carbon Dioxide / 40 mole % Reservoir Fluid System
Equilibrated at 950 psig at 108°F

**Equilibrium Gas Phase:**

57.26 volume % at 950 psig and 108°F
47.50 mole % at 950 psig and 108°F
0.1531 gm/cc at 950 psig and 108°F
0.680 Z-factor at 950 psig and 108°F

**Equilibrium Liquid Phase:**

42.74 volume % at 950 psig and 108°F
52.50 mole % at 950 psig and 108°F
0.8971 gm/cc at 950 psig and 108°F

**Table A-8. Injection Gas / Reservoir Fluid Equilibrium.**

## Chevron U.S.A. Production Company
**Well 11-8D 32 Fee**
**RFL 990039**

## Composition of Equilibrium Gas Phase
**( From Chromatographic Technique )**

| Component | Mol % | GPM | MW | Liq Dens (gm/cc) |
|---|---|---|---|---|
| Hydrogen Sulfide | 0.00 | | | |
| Carbon Dioxide | 87.04 | | 44.010 | .8172 |
| Nitrogen | 0.02 | | 28.013 | .8086 |
| Methane | 10.45 | | 16.043 | .2997 |
| Ethane | 1.76 | .470 | 30.070 | .3562 |
| Propane | 0.17 | .047 | 44.097 | .5070 |
| iso-Butane | 0.16 | .052 | 58.123 | .5629 |
| n-Butane | 0.07 | .022 | 58.123 | .5840 |
| iso-Pentane | 0.06 | .022 | 72.150 | .6244 |
| n-Pentane | 0.03 | .011 | 72.150 | .6311 |
| Hexanes | 0.06 | .023 | 84.000 | .6850 |
| Heptanes | 0.10 | .042 | 96.000 | .7220 |
| Octanes | 0.05 | .023 | 107.00 | .7450 |
| Nonanes | 0.02 | .010 | 121.00 | .7640 |
| Decanes | 0.01 | .005 | 134.00 | .7780 |
| Undecanes | Trace | | | |
| Dodecanes plus | Trace | | | |
| **Totals ...........** | 100.00 | 0.727 | | |

**Properties of Plus Fractions**

| Component | Mol % | MW | Liq Dens (gm/cc) | API Gravity |
|---|---|---|---|---|
| Heptanes plus | 0.18 | 103.9 | 0.737 | 60.3 |
| Decanes plus | 0.01 | 134.0 | 0.786 | 48.3 |

### Sampling Conditions

**950 psig**
**108 °F**

### Sample Characteristics
Core Lab sample number 207

| | |
|---|---|
| Critical Pressure (psia) ................................ | 1018.2 |
| Critical Temperature (°R) ............................ | 528.4 |
| Average Molecular Weight ........................ | 41.03 |
| Calculated Gas Gravity (air = 1.000) ........... | 1.417 |
| Gas Gravity Factor, Fg ................................................ | .8402 |
| Super Compressibility Factor, Fpv at sampling conditions ............................. | 1.2035 |
| Gas Z-Factor at sampling conditions * .......................... | 0.690 |

**at 14.73 psia and 60 °F**

| | |
|---|---|
| Heating Value, Btu/scf dry gas Gross ..................................................... | 165 |

* From: Standing, M.B., "Volumetric and Phase Behavior of Oil Field Hydrocarbon Systems", SPE (Dallas),1977, 8th Edition, Appendix II.

**Table A-9. Composition of Equilibrium Gas Phase.**

## Chevron U.S.A. Production Company
**Well 11-8D 32 Fee**
RFL 990039

## Composition of Equilibrium Liquid Phase
**(by Flash/Extended Chromatography)**

| Component Name | Mol % | Wt % | Density (gm/cc) | MW |
|---|---|---|---|---|
| Hydrogen Sulfide | 0.00 | 0.00 | 0.8006 | 34.08 |
| Carbon Dioxide | 44.53 | 12.54 | 0.8172 | 44.01 |
| Nitrogen | 0.00 | 0.00 | 0.8086 | 28.013 |
| Methane | 2.40 | 0.25 | 0.2997 | 16.043 |
| Ethane | 1.36 | 0.26 | 0.3562 | 30.07 |
| Propane | 0.31 | 0.09 | 0.5070 | 44.097 |
| iso-Butane | 0.52 | 0.19 | 0.5629 | 58.123 |
| n-Butane | 0.33 | 0.12 | 0.5840 | 58.123 |
| iso-Pentane | 0.47 | 0.22 | 0.6244 | 72.15 |
| n-Pentane | 0.32 | 0.15 | 0.6311 | 72.15 |
| Hexanes | 1.04 | 0.56 | 0.6850 | 84 |
| Heptanes | 3.69 | 2.39 | 0.7220 | 96 |
| Octanes | 4.45 | 3.05 | 0.7450 | 107 |
| Nonanes | 3.46 | 2.68 | 0.7640 | 121 |
| Decanes | 3.13 | 2.68 | 0.7780 | 134 |
| Undecanes | 2.50 | 2.35 | 0.7890 | 147 |
| Dodecanes | 2.29 | 2.36 | 0.8000 | 161 |
| Tridecanes | 2.29 | 2.57 | 0.8110 | 175 |
| Tetradecanes | 1.89 | 2.30 | 0.8220 | 190 |
| Pentadecanes | 1.71 | 2.26 | 0.8320 | 206 |
| Hexadecanes | 1.40 | 1.98 | 0.8390 | 222 |
| Heptadecanes | 1.23 | 1.87 | 0.8470 | 237 |
| Octadecanes | 1.16 | 1.86 | 0.8520 | 251 |
| Nonadecanes | 1.09 | 1.84 | 0.8570 | 263 |
| Eicosanes | 1.04 | 1.83 | 0.8620 | 275 |
| Heneicosanes | 0.97 | 1.80 | 0.8670 | 291 |
| Docosanes | 0.76 | 1.48 | 0.8720 | 305 |
| Tricosanes | 0.79 | 1.61 | 0.8770 | 318 |
| Tetracosanes | 0.59 | 1.26 | 0.8810 | 331 |
| Pentacosanes | 0.73 | 1.60 | 0.8850 | 345 |
| Hexacosanes | 0.52 | 1.19 | 0.8890 | 359 |
| Heptacosanes | 0.56 | 1.34 | 0.8930 | 374 |
| Octacosanes | 0.62 | 1.55 | 0.8960 | 388 |
| Nonacosanes | 0.55 | 1.42 | 0.8990 | 402 |
| Triacontanes plus | 11.10 | 40.35 | 1.0762 | 568 |
| Totals | 100.00 | 100.00 | | |

### Sampling Conditions

**950 psig**
**108 °F**

### Total Sample Properties

| | |
|---|---|
| Molecular Weight | 156.27 |
| Theoretical Liquid Density, gm/scc | 0.8968 |

| Plus Fractions | Mol % | Wt % | Density | MW |
|---|---|---|---|---|
| Hexanes plus | 49.76 | 86.18 | 0.9238 | 271 |
| Heptanes plus | 48.72 | 85.62 | 0.9259 | 275 |
| Decanes plus | 36.92 | 77.50 | 0.9502 | 328 |
| Pentadecanes plus | 24.82 | 65.24 | 0.9851 | 411 |
| Eicosanes plus | 18.23 | 55.43 | 1.0150 | 475 |
| Pentacosanes plus | 14.08 | 47.45 | 1.0440 | 527 |
| Triacontanes plus | 11.10 | 40.35 | 1.0762 | 568 |

**Table A-10. Composition of Equilibrium Liquid Phase.**

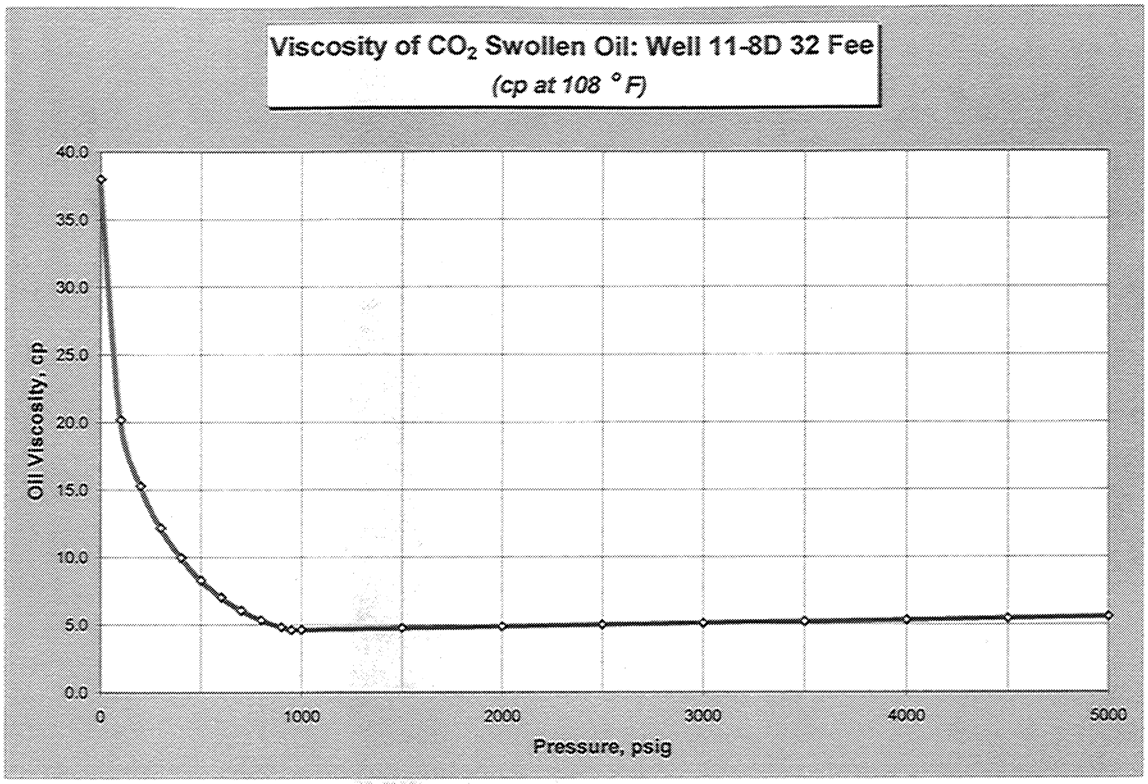



**Figure A-2. Viscosity of Equilibrium Liquid Phase or $CO_2$ Swollen Reservoir Fluid.**

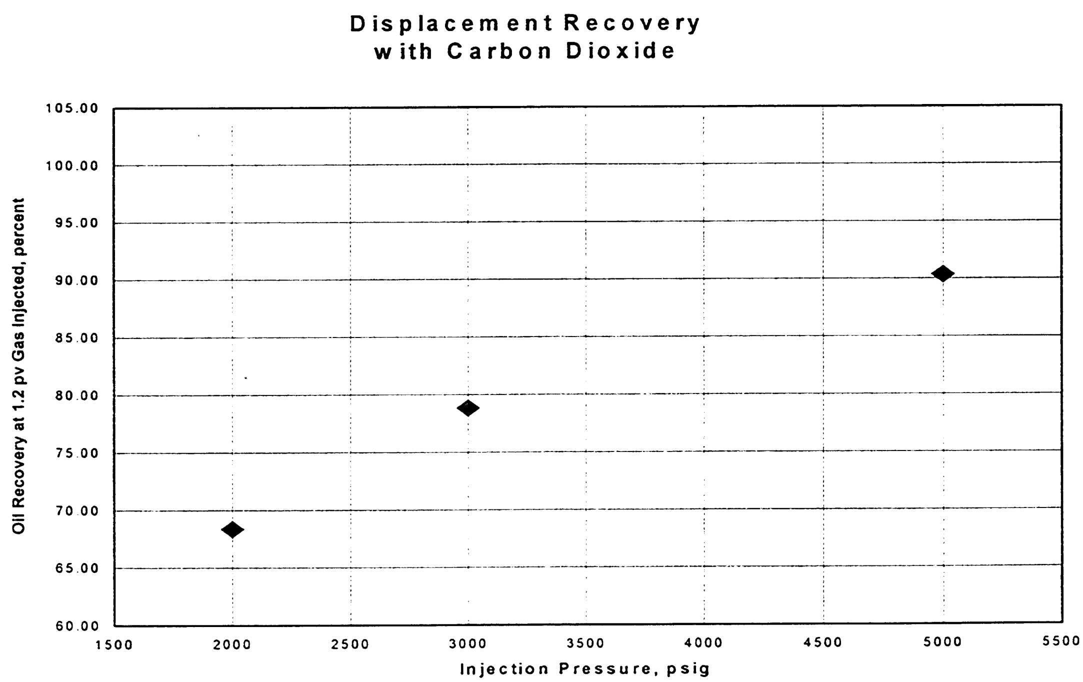
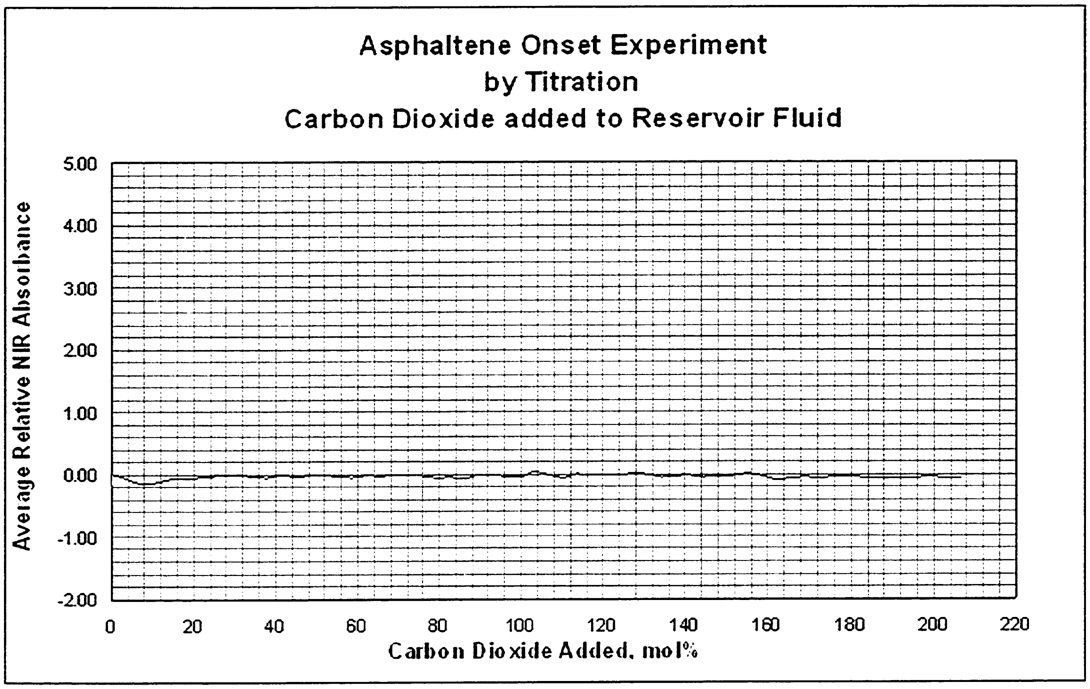



**Figure A-3. Summary of Packed Column Displacement Tests.**

Chevron U.S.A. Production Company
Well 11-8D 32 Fee
RFL 990039

Asphaltene Flocculation Experiment - NIR Scans
( From Near Infrared Spectroscopy Technique )
( at 108°F)
*No Onset Detected*



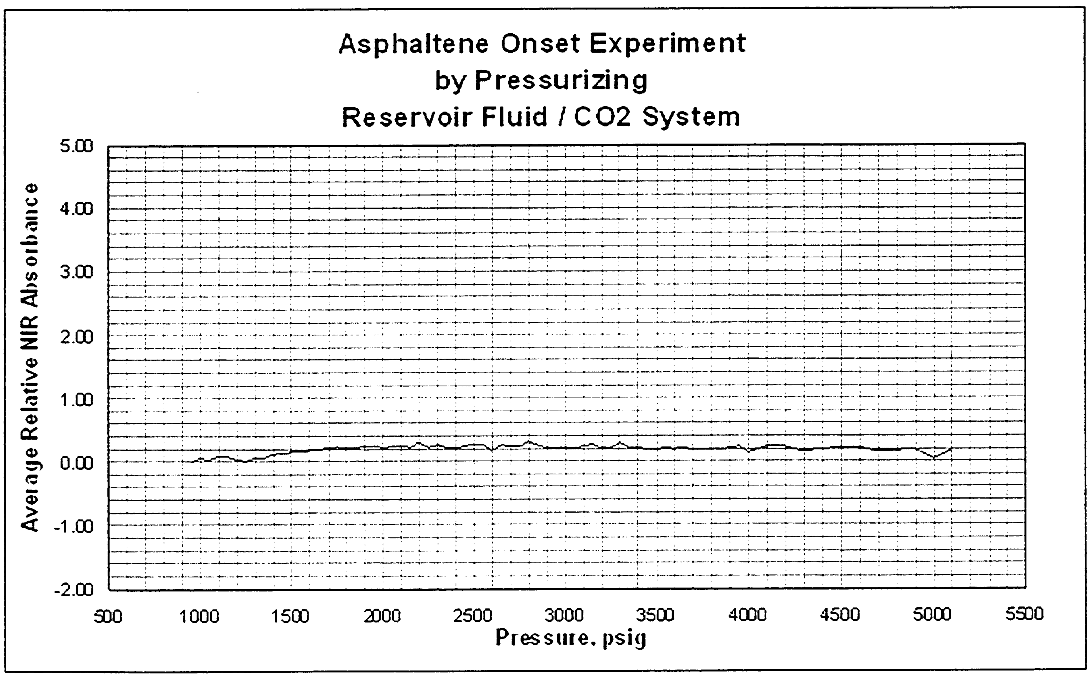




**Figure A-4. Asphaltene Experiment**

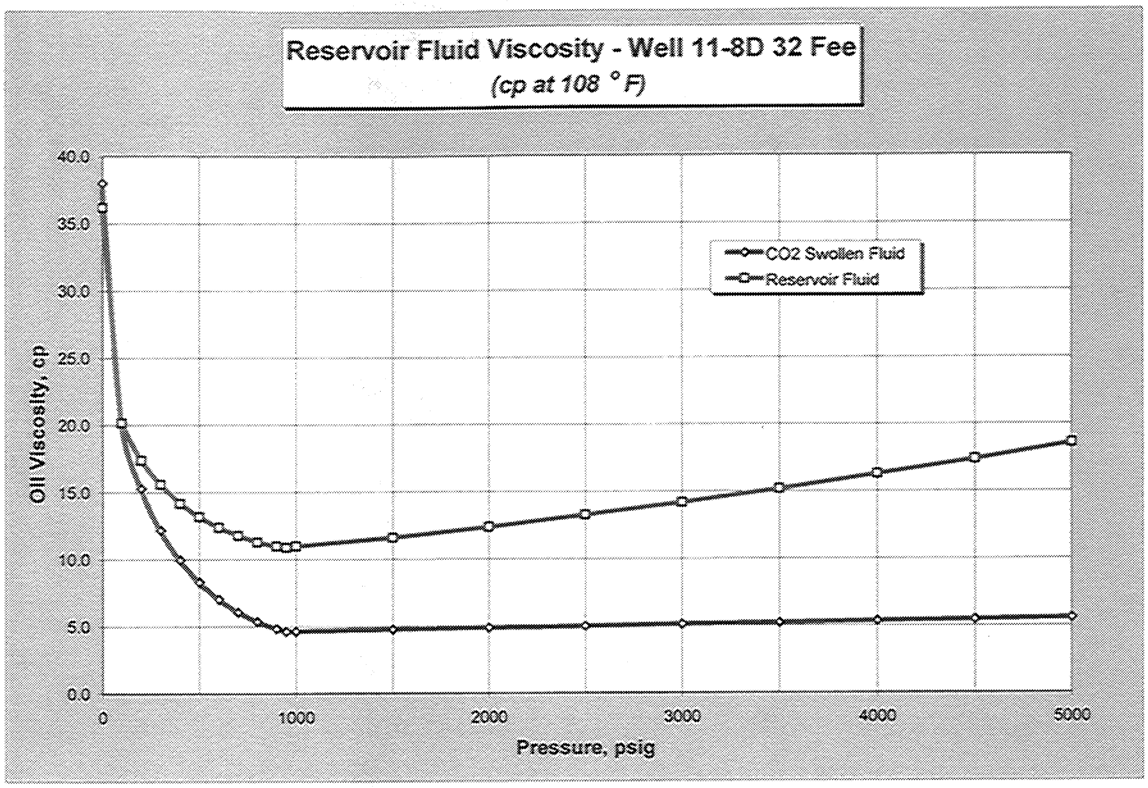



**Figure A-5. Viscosity Comparison of Original Reservoir Fluid and $CO_2$ Swollen Fluid.**

# APPENDIX B

# AVERAGE RESERVOIR PROPERTIES

Table B-1. Average Reservoir Properties for Lost Hills $CO_2$ Pilot.

| Geologic | Depth To Top | | Average | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Pressure | t | $\mu_o$ | h | k | $\phi$ | $S_o$ | $S_w$ | $S_g$ |
| Marker | VSS | Measured | (psig) | (°F) | cp | (ft) | (md) | (%) | (%) | (%) | (%) |
| C Pt. | 837 | 1233 | 149 | 97 | 18.6 | 139 | 1.16 | 43.7 | 33.4 | 61.6 | 5.0 |
| D Pt. | 976 | 1372 | 234 | 100 | 17.1 | 61 | 1.44 | 43.7 | 41.5 | 53.4 | 5.1 |
| DD Pt. | 1037 | 1433 | 280 | 101 | 16.1 | 79 | 1.44 | 52.8 | 42.2 | 52.7 | 5.1 |
| E Pt. | 1116 | 1512 | 347 | 102 | 15.6 | 48 | 1.22 | 51.8 | 40.3 | 54.4 | 5.3 |
| EE Pt. | 1164 | 1560 | 393 | 103 | 14.9 | 81 | 1.22 | 42.8 | 43.0 | 51.7 | 5.3 |
| F Pt. | 1245 | 1641 | 479 | 105 | 14.4 | 25 | 0.71 | 55.0 | 47.4 | 47.5 | 5.1 |
| FF Pt. | 1270 | 1666 | 507 | 105 | 13.5 | 33 | 0.71 | 46.9 | 45.2 | 49.7 | 5.1 |
| G Pt. | 1303 | 1699 | 547 | 106 | 13.2 | 80 | 0.47 | 51.8 | 46.1 | 49.0 | 4.9 |
| GG Pt. | 1383 | 1779 | 651 | 107 | 12.9 | 62 | 0.47 | 60.0 | 60.9 | 34.2 | 4.9 |
| H Pt. | 1445 | 1841 | 741 | 108 | 11.9 | 46 | 0.45 | 53.1 | 57.9 | 38.8 | 3.3 |
| BH Pt. | 1491 | 1887 | 812 | 109 | 11.2 | 77 | 0.45 | 52.2 | 47.8 | 48.9 | 3.3 |
| J Pt. | 1568 | 1964 | 941 | 110 | 10.7 | 54 | 0.28 | 60.0 | 62.0 | 37.2 | 0.8 |
| K Pt. | 1622 | 2018 | 1039 | 111 | 9.8 | 130 | 0.29 | 56.6 | 55.9 | 43.6 | 0.5 |
| L Pt. | 1752 | 2148 | 1303 | 114 | 9.1 | 100 | 0.29 | 51.0 | 41.1 | 58.4 | 0.5 |
| Average | 1301 | 1697 | 622 | 106 | 13.5 | 73 | 0.64 | 51.0 | 46.4 | 50.0 | 3.6 |
| Total | | | | | | 1015 | | | | | |

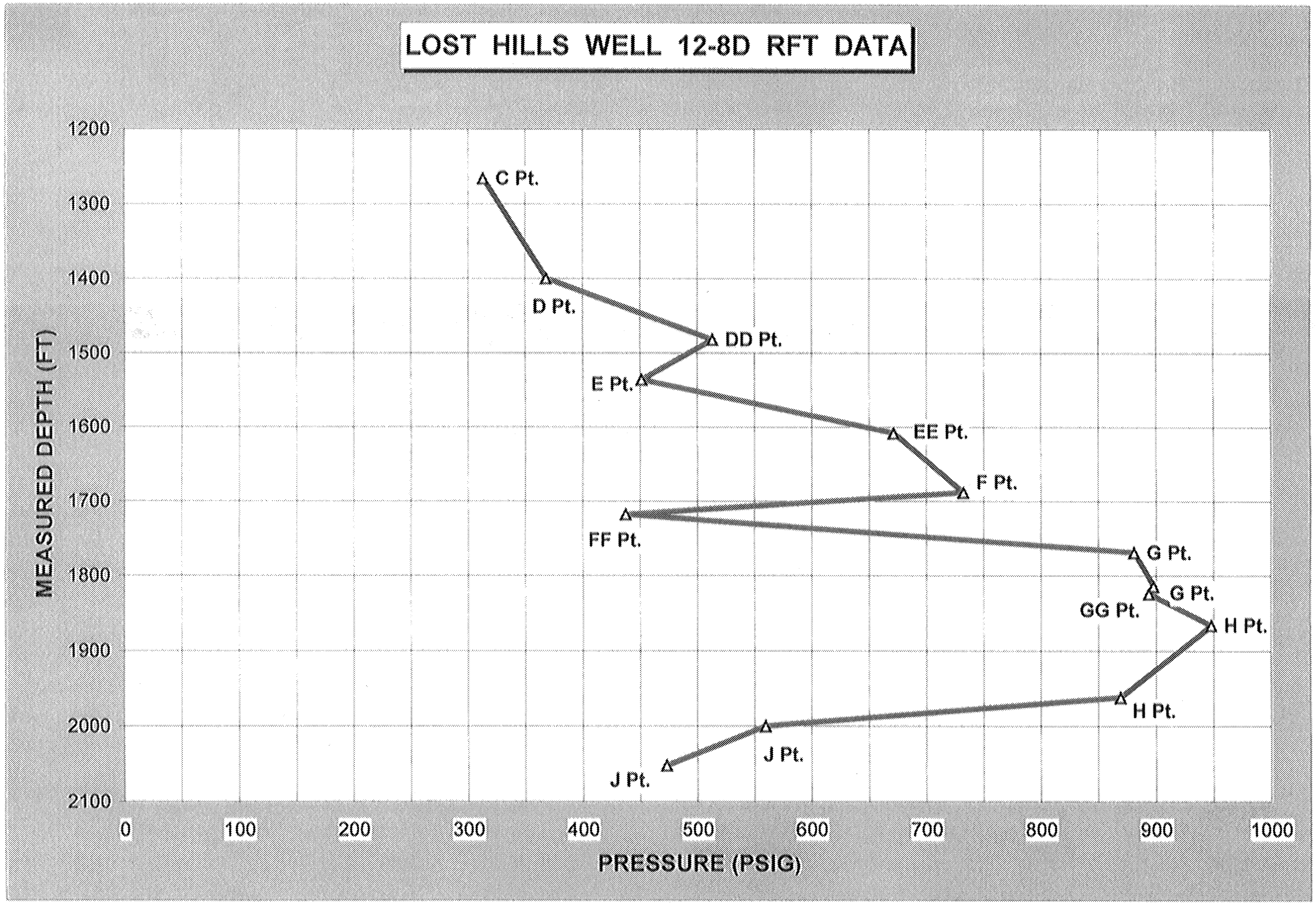



**Figure B-1. Average RFT Pressure Data for Lost Hills $CO_2$ Pilot.**

# APPENDIX C

# REVISED DOE SPENDING PLAN

# Table C-1. $CO_2$ Pilot Cost Summary Spreadsheet

**Lost Hills DOE Project**

**Project Tasks and Budget**

| Task Number and Name | Resources | Original Pilot Budget (12/98) | Revised Pilot Budget (10/99) | DOE SHARE (Note 1) | CHEVRON SHARE |
|---|---|---|---|---|---|
| | | | | | |
| | | | | | |
| **A. Project Management, Reporting, & Technlogy Transfer** | | | | | |
| A.1. Technology transfer throughout project (including Website) | CUSA/CPTC | $ 45,000 | $ 40,000 | $ 20,000 | $ 20,000 |
| A.2. DOE reporting throughout project | CUSA | $ 10,000 | $ 10,000 | $ 5,000 | $ 5,000 |
| A.3. Project management throughout project | CUSA | $ 45,000 | | $ - | $ - |
| **Subtotal for A:** | | $ 100,000 | $ 50,000 | $ 25,000 | $ 25,000 |
| | | | | | |
| **B. Prepare Proposal for DOE Phase II Funding - complete** | CUSA | | | | |
| **Subtotal for B:** | | $ - | | $ - | |
| | | | | | |
| **C. Injectivity Testing (Wells 12-8D & 12-7W) - complete** | | | | | |
| C.1. Complete Injectivity Well 12-8D | | | | | |
| C.2. Conduct Injectivity Test | Complete | | | | |
| C.3. Injectivity Test Evaluation/Report | CUSA | | | | |
| C.4. Oil Geochemistry - Asphaltene Propoensity | CPTC | | | | |
| C.5. Revise/update simulation model with new data | CPTC | | | | |
| **Subtotal for C:** | | Inject. Test Total Shown at bottom of page | | | |
| | | | | | |
| **D. Preliminary Facility Design (Complete)** | CUSA/ TJ Cross | | | | |
| D.1.Generate & evaluate alternative pilot designs | | $ - | $ - | $ - | $ - |
| D.2. Draft process design | | $ 10,000 | $ - | $ - | $ - |
| D.3. Review of Injectivity & Prelim. Design results w/Sponsors | | $ - | $ - | $ - | $ - |
| D.4. Finalize process design | | $ 20,000 | $ - | $ - | $ - |
| D.5. Prepare APCD permit application | | $ 10,000 | $ - | $ - | $ - |
| D.6. APCD permitting | | $ 5,000 | $ - | $ - | $ - |
| D.7. Set up pilot design team | | $ 5,000 | $ - | $ - | $ - |
| D.8. Prepare P&ID's and equipment spec's | | $ 100,000 | $ - | $ - | $ - |
| **Subtotal for D:** | | $ 150,000 | $ - | $ - | $ - |
| | | | | | |
| **E. Detailed Design Review** | CUSA | $ 5,000 | $ - | $ - | $ - |
| **Subtotal for E:** | | $ 5,000 | $ - | $ - | $ - |
| | | | | | |
| **F. Detailed Facility Design & Equipment Purchases** | CUSA/ TJ Cross | | | | |
| F.1. Long lead materials | | $ 1,200,000 | $ - | $ - | $ - |
| F.2. Detailed design -- CO2 Injection Facilities | | $ 400,000 | $ 35,000 | $ 17,500 | $ 17,500 |
| F.3. Detailed Design - Production & Gauging Facilities | | $ 120,000 | $ 45,000 | $ 22,500 | $ 22,500 |
| **Subtotal for F:** | | $ 1,720,000 | $ 80,000 | $ 40,000 | $ 40,000 |
| | | | | | |
| **G. Implement Well Work** | CUSA/ Schlumberger | | | | |
| G1. Remediate 4 Injectors (Replaces "Drill Producers") | | $ 1,800,000 | $ 280,000 | $ 140,000 | $ 140,000 |
| G.2. Drill & log pilot injectors (4) | | $ 800,000 | $ 1,200,000 | $ 600,000 | $ 600,000 |
| G.3. Drill, Log (Including C/0 for Baseline) 3 observation wells | | $ 140,000 | $ 400,000 | $ 200,000 | $ 200,000 |
| **Subtotal for G:** | | $ 2,740,000 | $ 1,880,000 | $ 940,000 | $ 940,000 |
| | | | | | |
| **H. Construction of Facilities** | J. E. Merit | | | | |
| H.1. Install Well Gauging Facilities & CVR System - 75% Chevron | | $ 215,000 | $ 825,000 | $ 206,250 | $ 618,750 |
| H.2. Install Remote Compression and Dehydration Facilities | | $ 750,000 | $ - | $ - | $ - |
| H.3. Install CO2 injection flowlines (Includes infrastructure such as roads for CO2 trucks) - **75% Chevron** | | $ 820,000 | $ 614,250 | 153,562.50 | $ 460,688 |
| H.4. Install CO2 injection facilities (Includes cost of removal and cancellation) | | $ 2,500,000 | $ 243,500 | $ 121,750 | $ 121,750 |
| H.5. Safety Walkthrough & Punchlist | | $ 10,000 | $ - | $ - | $ - |
| **Subtotal for H:** | | $ 4,295,000 | $ 1,682,750 | $ 481,563 | $ 1,201,188 |

## Table C-1. $CO_2$ Pilot Cost Summary Spreadsheet (continued)

### Lost Hills DOE Project

**Project Tasks and Budget**

| Task Number and Name | Resources | Original Pilot Budget (12/98) | Revised Pilot Budget (10/99) | DOE SHARE (Note 1) | CHEVRON SHARE |
|---|---|---|---|---|---|
| **I. Pilot Start-up Activities** | CUSA | | | | |
| I.1. Start up production facilities | | $ 5,000 | $ - | $ - | $ - |
| I.2. Start-up CO2 Injection Facilities | | $ 25,000 | $ - | $ - | $ - |
| I.3. Initiate CO2 injection with Permanent Supply | | $ 10,000 | $ - | $ - | $ - |
| **Subtotal for I:** | | **$ 40,000** | **$ -** | **$ -** | **$ -** |
| | | | | | |
| **J. Pilot Monitoring** | CUSA | | | | |
| Injector profiles | | $ 72,000 | $30,000 | $ 15,000 | $ 15,000 |
| Cased-hole resistivity logging and analysis | | $ 60,000 | $20,000 | $ 10,000 | $ 10,000 |
| Gas composition analysis | | $ 18,000 | $120,000 | $ 60,000 | $ 60,000 |
| Interwell tracers (inject in injectors, sample producers) | | $ 48,000 | $40,000 | $ 20,000 | $ 20,000 |
| Tiltmeter surveys | | $ 102,000 | $56,000 | $ 28,000 | $ 28,000 |
| EM Survey | | $ 48,000 | $50,000 | $ 25,000 | $ 25,000 |
| Cross-well seismic survey (LBL to Fund) | | | $25,000 | $ 12,500 | $ 12,500 |
| Static pressure surveys | | | $12,000 | $ 6,000 | $ 6,000 |
| Gas composition analysis | | | $12,000 | $ 6,000 | $ 6,000 |
| PVT Reservoir Fluid Sample and Analysis | | $ 120,000 | $15,000 | $ 7,500 | $ 7,500 |
| Static pressure surveys | | $ 24,000 | $12,000 | $ 6,000 | $ 6,000 |
| Corrosion coupons and probes | | $ - | $36,000 | $ 18,000 | $ 18,000 |
| **Subtotal for J:** | | **$ 492,000** | **$ 428,000** | **$ 214,000** | **$ 214,000** |
| | | | | | |
| **Pilot CAPEX Total:** | | **$ 9,542,000** | **$ 4,120,750** | **$ 1,700,563** | **$ 2,420,188** |
| | | | | | |
| **Additional Funding for Design/Scoping of Long Term CO2 Supply:** | | | **$ 250,000** | | **$ 250,000** |
| | | | | | |
| **CAPEX Total Including CO2 Project Scoping & Planning** | | | **$ 4,370,750** | **$ 1,700,563** | **$ 2,670,188** |
| | | | | | |
| **K. CO2 Injection Equipment & Purchases (MEJ: Expense Items)** | | | | | |
| K.1 Rental of CO2 Injection Equipment & Start-up assistance | BOC or Air Liquide | | $ 277,000 | $ 138,500 | $ 138,500 |
| K.2 Liquid CO2 Purchases (@ 1 MMscfd injection rate) - Note 3 | | | $ 2,555,000 | $ 620,000 | $ 1,935,000 |
| **Expense Total:** | | | **$ 2,832,000** | **$ 758,500** | **$ 2,073,500** |
| | | | | | |
| **Project Total Capital + Expense for 2 Years ($)** | | **$ 9,542,000** | **$ 6,952,750** | **$ 2,459,063** | **$ 4,743,688** |
| | | | | | |
| **DOE Expenditure Summary:** | | | | | |
| **Expenditures for Injectivity Test and Pilot Design (as of 10/1/99):** | | | **$ 646,000** | **$ 150,000** | **$ 496,000** |
| **Carry In from "DOE Phase I":** | | | | **$ 97,896** | |
| **Original Phase II DOE Funding:** | | | | **$ 2,515,406** | |
| **Available Phase II DOE Funding (= Phase I Carry In + Phase II Funding):** | | | | **$ 2,613,302** | |
| **Projected Phase II DOE Expenditiures** | | | | **$ 2,609,063** | |
| | | | | | |
| **Chevron Expenditure Summary:** | | | | | |
| **Chevron Capital Funding Requested for Pilot** | | | | | **$ 2,670,188** |
| **Total Chevron Expense Funding Requested** | | | | | **$ 2,073,500** |
| **Total New Chevron Funding (Capital + Expense) Requested** | | | | | **$ 4,743,688** |
| **Total Phase II Expenditures (Including Injectivity Test)** | | | | | **$ 5,424,688** |

**Note 1: Task Costs to be split 50/50 unless noted otherwise**
**Note 2: Charge codes for each task will be provided at a later date**
**Note 3: CAPEX for wells may be less - in which case DOE funding would be used to purchase CO2 (pending DOE approval)**